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February 15, 2017

Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

**RE: Application for Authority to Increase Electric Rates in North Dakota
Case No. PU-17-398
Otter Tail Power Company Petition to Reduce Interim Rates to Conform
to the Tax Cut & Jobs Act**

Dear Mr. Nitschke:

Otter Tail Power Company (Otter Tail) respectfully submits the enclosed Petition to Reduce Interim Rates to Conform to the Tax Cut & Jobs Act. Through this filing Otter Tail seeks Commission approval to reduce interim rates in conformity with recent federal tax reforms. We have proposed that the revised, lower rates go into effect March 1, 2018. Although this filing is framed as a petition supplementing Otter Tail's previously filed Alternative Petition for Interim Rates, we have enclosed a fifty-dollar filing required by N.D.C.C. 49-05-05 should the Commission deem this filing as notice of changes in tariff rates under that statute.

In support of the present filing, Otter Tail provides the following *Revised* documents from its November 2, 2017 Initial Filing:

- Volume 1, Interim Supporting Schedules and Workpapers Part A through Part D
- Volume 1, Interim Tariff Sheets – Legislative
- Volume 1, Interim Tariff Sheets – Non-Legislative
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 3, Page 1 and 2
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 4, Page 1 and 2
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 5, Page 1
- Volume 4a, Part C Interim Cost of Service Study.

Mr. Nitschke
February 15, 2018
Page 2

In addition, Otter Tail provides these additional documents:

- Volume 1, Interim Supporting Schedules and Workpapers, Part D.1, Page 1 of 1
 - This schedule compares the present interim rates that commenced January 1, 2018 and the proposed interim rates that OTP requests to implement March 1, 2018
- Bryce C. Haugen Exhibit __ (BCH-1), Schedule 6, Page 1 and 2
 - Originally established in Case No. PU-17-340, this schedule updates the Transmission Cost Recovery Rider rates that were implemented January 1, 2018 in that case with reduced rates Otter Tail requests to implement March 1, 2018.

An original and ten copies of this filing are being sent via mail. Please contact me at (218) 739-8956, or cstephenson@otpc.com should you have any questions with respect to this filing.

Very truly yours,

/S/ CARY STEPHENSON
Cary Stephenson
Associate General Counsel
Otter Tail Power Company

kaw
Enclosures
By electronic filing
c: Service List

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

In the Matter of the Application of
Otter Tail Power Company for
Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-17-398

**PETITION TO REDUCE INTERIM RATES
TO CONFORM TO THE TAX CUT & JOBS ACT**

A. Introduction

Otter Tail Power Company (Otter Tail or the Company) respectfully submits to the North Dakota Public Service Commission (Commission) this Petition to Reduce Interim Rates for its North Dakota retail electric customers. Otter Tail requests that the Commission approve the revised interim rate schedule, described herein, with an effective date of March 1, 2018.

This filing is made as a supplement to Otter Tail's Alternative Petition for Interim Rates in the above-entitled docket. To the extent that the Commission interprets Otter Tail's Petition to Reduce Interim Rates as notice of a change in tariff rates under N.D.C.C. § 49-05-05, Otter Tail respectfully requests that the Commission allow the requested changes to go into effect on less than thirty days' notice.

B. Background

On November 2, 2017 Otter Tail filed its Application for Authority to Increase Electric Rates (Case No. PU-17-398) seeking an annual increase of non-fuel base electric revenues of \$13,138,372 or 8.72 percent. Otter Tail included in its filing an Alternative Petition for Interim Rates, requesting that the Commission authorize, on an interim basis, rate relief of \$12,800,479 or 10.44 percent to be effective January 1, 2018.

On November 29, 2017, the Commission suspended the rates filed in Otter Tail Application. On December 20, 2017 the Commission issued an order approving the Company's

request for interim rates to increase annual revenue collection by \$12,800,479, effective for services rendered on after January 1, 2018.

On Dec. 22, 2017, President Trump signed the Tax Cut and Jobs Act (TCJA), which enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the maximum U.S. federal corporate income tax rate from 35 percent to 21 percent.¹

On January 10, 2018, the Commission ordered an investigation to determine the effect of the TCJA on investor-owned utilities serving customers in North Dakota². Among other things the Commission directed investor-owned utilities to file information regarding the impact of the TCJA with supporting calculations by February 15, 2018. Otter Tail has made a filing in Case No. PU-17-490 contemporaneously with this filing.

C. Description and Reasons for Reducing Interim Rates

The Company's evaluation of the impact of TCJA is on-going. There are numerous issues to assess. Although the Company's evaluation of the impacts of TCJA is not complete, there is sufficient information to support the reduction in interim rates requested in this filing. Federal corporate incomes taxes are a cost of service to our customers. The reduction of the federal corporate income tax rate from 35 percent to 21 percent reduces Otter Tail's cost of providing service. This results in a reduction in the gross-up factor Otter Tail uses to determine federal tax expense from 1.607756 to 1.322837.

Based on the foregoing, the Company seeks to reduce interim rates from 10.44% to 6.79%. If Otter Tail's request is approved, the revenue requirement for interim rates will be reduced from \$12.8 million to \$8.3 million, a total reduction in interim revenue of \$4.5 million. Otter Tail is also proposing to reduce rates in its Transmission, Renewable, and Environmental riders to further capture the impacts of the TCJA in those cost recovery mechanism. Adjusting those riders collectively reduces their revenue requirements by approximately \$1.7 million.

As noted in Otter Tail's comments in Case No. PU-17-490, Otter Tail believes its rate case, which uses a 2018 forecast test year, is the most efficient and accurate mechanism for identifying and passing on the beneficial impacts of the TCJA to our customers. Otter Tail

¹ In its final form, the TCJA recognizes the unique nature of public utilities and contains certain provisions specific to the industry, including the continuation of certain interest expense deductibility and relief from 100 percent expensing of capital investments.

² Public Service Commission Rate Impact & Accounting Treatment Investigation, Case No. PU 17-490.

anticipates filing supplemental direct testimony in this docket in March 2018, that will, among other things, address the impact of the TCJA on the Company's Application to increase electric rates in North Dakota.

D. Revised Interim Rate Schedules

The Company requests a reduction of interim rates from 10.44 percent to 6.79 percent. The following revised rate schedules are proposed to be revised on an interim basis on March 1, 2018:

<u>RESIDENTIAL AND WATER HEATING SERVICE</u>		Section
Residential Service		9.01
Residential Service (Controlled Demand)		9.02
<u>FARM SERVICE</u>		
Farm Service		9.03
<u>GENERAL AND COMMERCIAL SERVICE</u>		
Small General Service		10.01
General Service (20 kW or Greater)		10.02
Large General Service		10.03
Commercial Service – Time of Use		10.04
Large General Service- Time of Day- Experimental		10.05
<u>INTERRUPTIBLE SERVICE</u>		
Water Heating Control Rider		14.01
Controlled Service - Interruptible Load CT Metering		14.04
Controlled Service - Interruptible Load Self Contained Metering		14.05
Controlled Service - Deferred Load		14.06
Fixed Time of Delivery Service		14.07
<u>PURCHASE POWER RATE SCHEDULES</u>		
Small Power Producer Rider - Occasional Delivery		12.01
Small Power Producer Rider - Time of Delivery		12.02
Small Power Producer Rider - Dependable Service		12.03
<u>OTHER ELECTRIC RATE SCHEDULES</u>		
Standby Service		11.01
Irrigation Service		11.02
Outdoor Lighting – Energy Only		11.03
Outdoor Lighting		11.04
Municipal Pumping Service		11.05
Fire Sirens		11.06

The following updated rate schedules are also proposed to be implemented on March 1, 2018, coinciding with interim rates, to reflect the impact of changes from the TCJA:

<u>MANDATORY RIDERS</u>	<u>Section</u>
Renewable Cost Recovery Rider	13.04
Transmission Cost Recovery Rider	13.07
Environmental Costs Recovery Rider	13.08

The revised rate schedules containing lowered interim rates and lowered Mandatory Rider Rates are included along with this Petition (legislative and regular formats, respectively). No change has been made in the existing rate design. No change has been made to the base cost of energy set forth in the initial filing. The request decreases interim rates from \$12.8 million to \$8.3 million, on an annualized basis, in base rate revenue currently being recovered from each customer class; a reduction of \$4.5 million. The impact of the TCJA also reduces the Environmental, Renewable, and Transmission³ Cost Recovery Rider annualized revenue requirements from \$26.5 million to \$24.8 million; a reduction of approximately \$1.7 million to the revenue requirements used to establish current rates that were effective January 1, 2018. As a result, Otter Tail is requesting that the rates in these riders also be lowered to reduce collections in these riders associated with the TCJA. The updated lower rates are provided in the attached Mandatory Rider tariff sheets.

E. Supporting Schedules and Workpapers

Attached to this filing are Schedules and Workpapers offered in support of the Company's request to lower interim rates.

F. Interim Bills

The Company proposes to include an informational statement in customer bills beginning March 1, 2018 to communicate to customers that their bill reflects a reduction in Otter Tail's

³ Otter Tail expects further adjustments to the Transmission Rider for MISO and SPP related revenues and expense as impacts of the TCJA are incorporated into those Federal Energy Regulatory Commission (FERC) authorized rates. These adjustments will be incorporated into future Transmission Rider updates to true-up the impacts in the rider once approved by FERC and amounts become known.

interim rate request due to the Tax Cut and Jobs Act. The proposed informational statement provides the following:

We're passing savings from the reduced corporate tax rate to our North Dakota customers by lowering interim rates from 10.44% to 6.79% beginning March 1, 2018. The lower interim rates will remain in effect until the NDPSC determines our new final rates later this year.

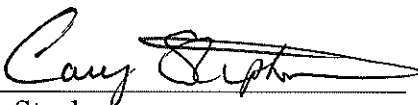
G. Conclusion

The Company respectfully requests that the Commission grant the Company permission to reduce interim rates as described herein.

Dated: February 15, 2018

Respectfully Submitted,

OTTER TAIL POWER COMPANY

By 

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
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**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Case No. PU-17-398

In the Matter of Otter Tail Power
Company's Application for Authority
To Increase Rates for Electric Service
In North Dakota

CERTIFICATE OF SERVICE

Kim A. Ward certifies that on the 15th day of February, 2018, she served a true and correct copy of the attached PETITION TO REDUCE INTERIM RATES TO CONFORM TO THE TAX CUT AND JOBS ACT by email addressed to the following individuals:

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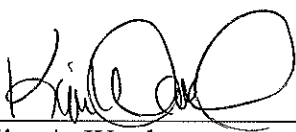
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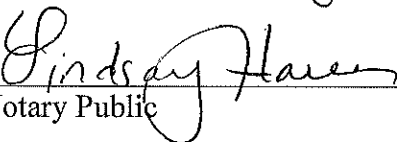


Kim A. Ward

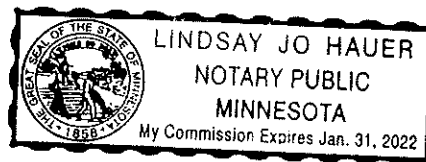
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Subscribed and sworn to before me this
15th day of February, 2018



Notary Public



**INTERIM RATE SCHEDULES
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Summary of Revenue Requirements	1

**OTTER TAIL POWER COMPANY
INTERIM RATE INCREASE
REVENUES & PERCENT INCREASE**

**Case No. PU-17-398
PART A
Revised Schedule 1
Page 1 of 1**

Total Interim Retail Revenues

\$122,589,268

Interim Deficiency

\$8,319,184

Total Interim Revenue % Increase

6.79%

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
Policy Statements**

**Case No. PU-17-398
PART A
Revised Schedule 2
Page 1 of 2**

**DESCRIPTION OF INTERIM RATE APPLICATION,
SUPPORTING SCHEDULES AND WORKPAPERS**

The supporting schedules include the following:

1) A schedule showing the interim rate of return calculation. These schedules show the capital structure and rate of return calculation approved by the Commission in the most recent general rate case; the capital structure and rate of return calculation proposed for interim rates; and a description and corresponding dollar amount of any changes between the two capital structures.

Note:

Part C, Schedule 7, contains this information.

2) A schedule showing the interim operating income statement. These schedules show the same operating income statement accounts as filed in the general rate case. Also, the schedules include the operating income statement approved by the Commission in the most recent general rate case, the operating income statement for the unadjusted projected fiscal year, and the operating income statement proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the operating income statements should be provided. Workpapers should be provided which show how revenues, taxes, expenses, and other income statement components have been determined.

Notes:

Part C, Schedule 3, compares the operating income statement approved by the Commission in the most recent general rate case with the income statement for the proposed interim test year, including a description of all changes and corresponding dollar amounts.

OTP includes as Part B, Schedule 6, an operating statement bridge schedule for the proposed interim test year, as well as Part B, Schedule 4, a comparison of proposed interim rates to the statement of operating income for the proposed test year with the income statement for the proposed interim test year that includes a description of all known and measurable adjustments and corresponding dollar amounts.

Workpapers for the above Interim Rate Petition Schedules are located in Volume 4 of this filing.

**DISCUSSION OF INTERIM RATE APPLICATION,
SUPPORTING SCHEDULES AND WORKPAPERS**

3) A schedule showing the interim proposed rate base. These schedules show the same rate base accounts as filed in the general rate case. These schedules include the average rate base approved by the Commission in the most recent general rate case; the average rate base with the unadjusted projected fiscal year, and the average rate base proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the rate bases is provided. Workpapers are provided which show how the rate base components are determined.

Notes:

Part C, Schedule 1, compares the average rate base approved by the commission in the most recent general rate case with the average rate base proposed for interim rates, including a description of all changes and corresponding dollar amounts.

4) OTP includes as Part B, Schedule 1, comparison of the average rate base for the proposed test year with the average rate base for the proposed interim test year, as well as Part B, Schedule 3, a bridge schedule of the average rate base for the proposed test year with the average rate base for the proposed interim test year that includes a description of all known and measurable adjustments and corresponding dollar amounts.

Workpapers for the above Interim Rate Petition Schedules are located in Volume 1 of this filing. The Interim Jurisdictional Cost of Service Study is located in Volume 4A, Section C.

A schedule showing revenue deficiency calculations for each of the operating income statements and rate bases requested in (2) and (3) above. The revenue deficiency is calculated for the actual data and the interim data using the rate of return calculated in (1) above.

Notes:

Part C, Schedule 5, shows the revenue deficiency calculations for the most recent general rate case and for the proposed interim rates.

OTP includes as Part B, Schedule 7 of this volume, the revenue deficiency calculations for this general rate case filing and for the proposed interim rates.

DEFINITIONS

The following definitions are used in this filing:

Proposed Interim Test Year

The proposed interim test year information is for the calendar year ending December 31, 2018 and includes the effect of rate making adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

Present Interim Test Year

The present interim test year information is for the calendar year ending December 31, 2018 and includes the effect of rate making adjustments for interim rates included in Otter Tail Power's initial filing, November 2, 2017. The interim rates were approved on December 20, 2017 and went into effect January 1, 2018.

Proposed Test Year

The proposed test year information represents the test year financial information for the 2018 calendar year and includes the effects of rate making adjustments for final rates.

Most Recent General Rate Case

This information represents the financial data for the 12 months test year ending December 31, 2007, from Otter Tail Power Company's last North Dakota electric rate case (Case No. PU-08-862), as approved by the Commission.

Note on Rounding

The cost of service study on which these supporting schedules are based rounds numbers to the nearest whole dollar for display purposes. However, the subtotals and subsequent totals in the cost of service study may be based on actual values resulting in occasional differences in the totals displayed when compared to the sum of the line items. These supporting schedules were prepared using individual line items with subtotals and totals calculated on each schedule separately. This may result in occasional rounding differences of a few dollars when comparing between the subtotals and totals on the cost of service study to those on the supporting schedules.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
SUMMARY OF REVENUE REQUIREMENTS

Case No. PU-17-398
PART A
Revised Schedule 4
Page 1 of 1

Line No.	Description	Proposed Interim Test Year
1	Average Rate Base	\$223,306,066
2	Operating Income (Before AFUDC)	\$11,486,268
3	Allowance for Funds Used During Construction (AFUDC)	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	11,486,268
5	Overall Rate of Return (Line 4 / Line 1)	5.14%
6	Required Rate of Return	7.96%
7	Operating Income Requirement (Line 1 x Line 6)	\$17,775,163
8	Income Deficiency (Line 7 - Line 4)	\$6,288,895
9	Gross Revenue Conversion Factor	1.32284
10	Revenue Deficiency (Line 8 x Line 9)	\$8,319,184
11	Retail Related Revenues Under Present Rates	\$122,589,268
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	6.79%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
STATEMENT OF OPERATING INCOME

Case No. PU-17-398
PART A
Revised Schedule 5
Page 1 of 1

Line No. Description	Proposed Interim Test Year
<u>OPERATING REVENUES</u>	
1 Retail	\$122,589,268
2 Other Operating Revenue	<u>\$9,712,037</u>
3 TOTAL OPERATING REVENUE	\$132,301,305
<u>OPERATING EXPENSES</u>	
5 Production Expenses	\$58,417,943
6 Transmission Expenses	11,026,754
7 Distribution Expenses	7,680,921
8 Customer Accounting Expenses	6,091,579
9 Customer Service & Information Expenses	1,382,509
10 Sales Expenses	22,472
11 Administration & General Expenses	19,282,795
12 Charitable Contributions	0
13 Depreciation Expense	13,387,642
14 General Taxes	<u>3,936,734</u>
15 TOTAL OPERATING EXPENSES	<u>\$121,229,349</u>
16 NET OPERATING INCOME BEFORE INCOME TAXES	\$11,071,955
<u>INCOME TAX EXPENSE</u>	
18 Investment Tax Credit	(\$1,183,682)
19 Deferred Income Taxes	(1,639,469)
20 Income Taxes	<u>2,408,839</u>
21 TOTAL INCOME TAX EXPENSE	<u>(\$414,312)</u>
22 NET OPERATING INCOME	\$11,486,268
23 Allowance for Funds Used During Construction	<u>0</u>
24 TOTAL AVAILABLE FOR RETURN	<u><u>\$11,486,268</u></u>

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
PART A
Revised Schedule 6
Page 1 of 1

Line No. Description	Proposed Interim Test Year
Utility Plant in Service:	
1 Production	\$154,188,768
2 Transmission	104,672,321
3 Distribution	228,593,947
4 General	36,081,097
5 Intangible	5,727,482
6 TOTAL Utility Plant in Service	\$529,263,615
Accumulated Depreciation	
8 Production	(\$98,334,309)
9 Transmission	(45,254,234)
10 Distribution	(98,387,399)
11 General	(13,900,914)
12 Intangible	(818,591)
13 TOTAL Accumulated Depreciation	(\$256,695,448)
14 NET Utility Plant in Service	
15 Production	\$55,854,459
16 Transmission	59,418,086
17 Distribution	130,206,548
18 General	22,180,183
19 Intangible	4,908,890
20 NET Utility Plant in Service	\$272,568,167
21 Utility Plant Held for Future Use	\$13,044
22 Construction Work in Progress	271,747
23 Materials and Supplies	7,946,645
24 Fuel Stocks	4,430,805
25 Prepayments	(12,739,580)
26 Customer Advances & Deposits	(353,143)
27 Cash Working Capital	3,548,095
28 Accumulated Deferred Income Taxes	(52,379,715)
29 Total Average Rate Base	\$223,306,066

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
PROPOSED TEST YEAR
DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
PART B
Revised Schedule 1
Page 1 of 1

Line No.	Description	(A) Proposed Test Year 2018	(B) Proposed Interim Test Year	(C) Change (B) - (A)
Utility Plant in Service:				
1	Production	\$330,519,065	\$154,188,768	(\$176,330,297)
2	Transmission	153,826,930	104,672,321	(49,154,609)
3	Distribution	228,593,947	228,593,947	0
4	General	36,403,979	36,081,097	(322,882)
5	Intangible	9,051,224	5,727,482	(3,323,742)
6	TOTAL Utility Plant in Service	\$758,395,144	\$529,263,615	(\$229,131,529)
Accumulated Depreciation				
7	Production	(\$142,605,272)	(\$98,334,309)	\$44,270,963
8	Transmission	(48,351,302)	(45,254,234)	3,097,068
9	Distribution	(98,387,399)	(98,387,399)	0
10	General	(14,025,311)	(13,900,914)	124,396
11	Intangible	(1,383,019)	(818,591)	564,428
12	TOTAL Accumulated Depreciation	(\$304,752,302)	(\$256,695,448)	\$48,056,855
13	NET Utility Plant in Service			
14	Production	\$187,913,793	\$55,854,459	(\$132,059,334)
15	Transmission	105,475,628	59,418,086	(46,057,541)
16	Distribution	130,206,548	130,206,548	0
17	General	22,378,668	22,180,183	(198,485)
18	Intangible	7,668,205	4,908,890	(2,759,314)
19	NET Utility Plant in Service	\$453,642,842	\$272,568,167	(\$181,074,675)
20				
21	Utility Plant Held for Future Use	\$13,044	\$13,044	\$0
22	Construction Work in Progress	271,747	271,747	0
23	Materials and Supplies	8,275,549	7,946,645	(328,904)
24	Fuel Stocks	4,430,805	4,430,805	0
25	Prepayments	(13,199,141)	(12,739,580)	459,562
26	Customer Advances & Deposits	(365,882)	(353,143)	12,739
27	Cash Working Capital	3,602,273	3,548,095	(54,178)
28	Accumulated Deferred Income Taxes	(102,479,471)	(52,379,715)	50,099,756
29	Total Average Rate Base	\$354,191,766	\$223,306,066	(\$130,885,700)

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
DETAILED RATE BASE COMPONENTS
DESCRIPTION OF ADJUSTMENTS

Case No. PU-17-398
PART B
Revised Schedule 2
Page 1 of 1

There are a total of eight adjustments that convert the Rate Base of the Proposed Test Year to the Rate Base Proposed for Interim Rates. A bridge from the Proposed Test Year rate base to the Interim Rate Petition rate base is provided in Part B, Schedule 3.

Net Electric Plant in Service (4 related adjustments - Columns B, C, D, and E)

OTP's proposed 2018 Test year requests approval to include costs currently included in the Environmental Cost Recovery Rider (ECRR), Renewable Resource Adjustment Rider (RRAR), Transmission Cost Recovery Rider (TCRR) to be included in base rates at the conclusion of the general rate case. OTP also includes a plant normalization adjustment in its 2018 Test Year. An adjustment was made to the Interim Rate Application to remove the costs associated with these four items. The riders remain in effect during the interim period and the plant normalization is not considered like-kind.

Prorate ADIT (Column F)

To comply with IRS Regulation Section 1.167(l)-1(h)(6), a positive interim rate adjustment is made to include the difference between the required proration of Accumulated Deferred Income Taxes (ADIT) for the five future months (August to December) of the test year for purposes of computing final rates that are assumed to be effective August 1, 2018, and the proration of ADIT for the 12 future months (January to December) of the interim period for purposes of computing interim rates to be effective January 1, 2018.

Cash Working Capital (Column G)

A positive interim rate adjustment made to Materials and Supplies accounts for the removal of the RRAR, and their associated impacts on operation and maintenance expense, property tax expense, and income tax expense components of the Cash Working Capital calculation. The Cash Working Capital requirement is determined through the application of Lead-Lag study factors against applicable expense categories.

Changes in Allocations due to Interim Rate Adjustments (Column H)

OTP uses its jurisdictional cost of service study (JCOSS) model to calculate all operating statement and rate base schedules for both interim rates and the application for final rates. Certain allocation factors are developed within the JCOSS model. Any adjustment has the potential to change some of these allocation factors. This column shows the effect of the allocations on rate base components caused by adjustments.

Changes in Allocations due to Tax Cuts and Jobs Act (Column H.1)

Tax reform related adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 RATE BASE WITH ADJUSTMENTS (BRIDGE SCHEDULE)

Case No. PU-17-398
 PART B
 Revised Schedule 3
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Line No.	Description	(A) Proposed Test Year 2018	(B) Environmental Rider Amounts Removed	(C) Renewable Rider Amounts Removed	(D) Transmission Rider Amounts Removed	(E) Plant Normalization Intangible Plant Removed	(F) Prorate ADIT Interim Adjust	(G) Impact of Operating Statement Adjustments on Cash Working Capital	(H) Changes in Allocations Due to Effect of Interim Adjustments	(H.1) Changes Due to Tax Cuts and Jobs Act	(I) Proposed Interim Test Year (1)	
1	Electric Plant in Service *	\$758,395,144	(\$73,882,796)	(\$102,447,501)	(\$49,154,609)	(\$3,243,463)	\$0	\$0	(\$403,161)	\$0	\$529,263,614	
2	Less: Accumulated Depreciation*	(304,752,302)	6,611,697	37,659,265	3,097,068	552,161	0	0	\$136,863	\$0	(256,695,448)	
3	Net Electric Plant in Service	\$453,642,842	(\$67,271,099)	(\$64,788,235)	(\$46,057,541)	(\$2,691,302)	\$0	\$0	(\$266,498)	\$0	\$272,568,167	
4	Other Rate Base Components:											
5	Plant Held for Future Use	\$13,044	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$13,044	
6	Construction Work in Progress	271,747	0	0	0	0	0	0	0	0	271,747	
7	Materials and Supplies	8,275,549	0	(269,180)	0	0	0	0	(59,724)	0	7,946,644	
8	Fuel Stocks	4,430,805	0	0	0	0	0	0	0	0	4,430,805	
9	Prepayments	(13,199,141)	0	0	0	0	0	0	459,562	0	(12,739,579)	
10	Customer Advances	(365,882)	0	0	0	0	0	0	12,739	0	(353,143)	
11	Cash Working Capital	3,602,273	0	0	0	0	0	(213,186)	65,794	93,214	3,548,095	
12	Accumulated Deferred Income Taxes	(102,479,471)	15,369,438	22,453,136	8,252,217	0	855,999	0	2,258,213	910,753	(52,379,715)	
13												
14	TOTAL	\$354,191,766	(\$51,901,660)	(\$42,604,280)	(\$37,805,324)	(\$2,691,302)	\$855,999	(\$213,186)	\$2,470,086	\$1,003,967	\$223,306,066	

(1) Electric Utility - North Dakota Jurisdiction

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
STATEMENT OF OPERATING INCOME

Case No. PU-17-398
PART B
Revised Schedule 4
Page 1 of 1

Line No.	Description	(A) Proposed Test Year 2018	(B) Proposed Interim Test Year	(C) Change (B) - (A)
<u>OPERATING REVENUES</u>				
1	Retail	\$148,071,948	\$122,589,268	(\$25,482,680)
2	Other Operating Revenue	10,047,294	9,712,037	(335,257)
3	TOTAL OPERATING REVENUE	\$158,119,242	\$132,301,305	(\$25,817,937)
<u>OPERATING EXPENSES</u>				
5	Production Expenses	\$59,756,799	\$58,417,943	(\$1,338,856)
6	Transmission Expenses	13,507,453	11,026,754	(2,480,698)
7	Distribution Expenses	7,680,921	7,680,921	0
8	Customer Accounting Expenses	6,091,579	6,091,579	0
9	Customer Service & Information Expenses	1,382,509	1,382,509	0
10	Sales Expenses	222,472	22,472	(200,000)
11	Administration & General Expenses	19,596,616	19,282,795	(313,821)
12	Charitable Contributions	0	0	0
13	Depreciation Expense	21,425,301	13,387,642	(8,037,659)
14	General Taxes	4,905,891	3,936,734	(969,158)
15	TOTAL OPERATING EXPENSES	\$134,569,541	\$121,229,349	(\$13,340,192)
16	NET OPERATING INCOME BEFORE INCOME TAXES	\$23,549,700	\$11,071,955	(\$12,477,745)
<u>INCOME TAX EXPENSE</u>				
18	Investment Tax Credit	(\$526,207)	(\$1,183,682)	(\$657,475)
19	Deferred Income Taxes	1,317,384	(1,639,469)	(2,956,853)
20	Income Taxes	4,304,133	2,408,839	(1,895,294)
21	TOTAL INCOME TAX EXPENSE	\$5,095,310	(\$414,312)	(\$5,509,622)
22	NET OPERATING INCOME	\$18,454,391	\$11,486,268	(\$6,968,123)
23	Allowance for Funds Used During Construction	0	0	0
24	TOTAL AVAILABLE FOR RETURN	\$18,454,391	\$11,486,268	(\$6,968,123)

Notes: Revenues reflect calendar month sales

Part B, Schedule 6, contains a bridge schedule itemizing the changes from the Proposed Test Year operating income statement to the Interim Rate Petition operating income statement. Nine adjustments were made to bridge the Proposed Test Year operating income statement to the Proposed Interim operating income statement.

Adjustment to Remove Rider Costs (Columns B, C, D)

An adjustment was made to remove the costs currently tracked in the ECRR, RRA, and TCRR that OTP is proposing to move to base rates in the Proposed Test Year. Since the rider will remain in effect during the interim period, an adjustment is needed to remove the costs from interim rates to avoid double recovery.

Adjustment to remove Economic Development Costs (Column E)

An adjustment was made to remove the Economic Development costs included in the 2018 Test Year. These costs are not considered like-kind and not eligible for interim rate recovery.

Adjustment to remove Plant Normalization (Column F)

An adjustment was made to remove the expenses related to the Plant Normalization adjustment. These costs are not considered like-kind and not eligible for interim rate recovery.

Adjustment to remove PTC Normalization (Column G)

An adjustment was made to remove the PTC normalization. During the Interim Period, PTCs flow through the RRAR. This adjustment is needed to avoid double recovery.

Changes in Allocations due to Interim Rate Adjustments (Column H)

OTP uses its jurisdictional cost of service study (JCOSS) model to calculate all operating statement and rate base schedules for both interim rates and the application for final rates. Certain allocation factors are developed within the JCOSS model. Any adjustment has the potential to change some of these allocation factors. This column shows the effect of the allocations on the operating statement components caused by adjustments.

Changes in Allocations due to Tax Cuts and Jobs Act (Column H.1)

Tax reform related adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 STATEMENT OF OPERATING INCOME WITH ADJUSTMENTS (BRIDGE SCHEDULE)

Line No.	Description	(A) Proposed Test Year 2018	(B) Environmental Rider Amounts Removed	(C) Renewable Rider Amounts Removed	(D) Transmission Rider Amounts Removed	(E) Economic Development Remove	(F) Plant Normalization Remove	(G) PTC Normalization Remove	(H) Changes in Allocations Due to Effect of Interim Adjustments	(H.1) Changes Due to Tax Cuts and Jobs Act	(I) Proposed Interim Test Year
OPERATING REVENUES											
1	Retail	\$148,071,948	(\$7,581,594)	(\$8,871,617)	(\$7,391,542)	\$0	\$0	\$0	\$0	(\$1,637,927)	\$122,589,268
2	Other Operating Revenue	10,047,294	0	0	0 *	0	\$0	\$0	(335,257)	0	9,712,037
3	TOTAL OPERATING REVENUE	\$158,119,242	(\$7,581,594)	(\$8,871,617)	(\$7,391,542)	\$0	\$0	\$0	(\$335,257)	(\$1,637,927)	\$132,301,305
OPERATING EXPENSES											
4	Production Expenses	\$59,756,799	(\$230,588)	(1,108,268)	\$0	\$0	\$0	\$0	\$0	\$0	58,417,943
5	Transmission Expenses	13,507,453	0	0	(2,480,698)	0	0	0	0	0	11,026,754
6	Distribution Expenses	7,680,921	0	0	0	0	0	0	0	0	7,680,921
7	Customer Accounting Expenses	6,091,579	0	0	0	0	0	0	0	0	6,091,579
8	Customer Service & Information Expenses	1,382,509	0	0	0	0	0	0	0	0	1,382,509
9	Sales Expenses	222,472	0	0	0	(\$200,000)	0	0	0	0	22,472
10	Administration & General Expenses	19,596,616	0	(210,167)	0	0	0	0	(103,654)	0	19,282,795
11	Charitable Contributions	0	0	0	0	0	0	0	0	0	0
12	Depreciation Expense	21,425,301	(\$2,377,681)	(\$4,240,716)	(693,135)	0	(\$702,750)	\$0	(23,377)	0	13,387,642
13	General Taxes	4,905,891	0	(145,116)	(694,892)	0	0	0	(129,149)	0	3,936,734
14	TOTAL OPERATING EXPENSES	\$134,569,541	(\$2,608,269)	(\$5,704,267)	(\$3,868,725)	(\$200,000)	(\$702,750)	\$0	(\$256,180)	\$0	\$121,229,349
15	NET OPERATING INCOME BEFORE INCOME TAXES	\$23,549,700	(\$4,973,325)	(\$3,167,349)	(\$3,522,817)	\$200,000	\$702,750	\$0	(\$79,077)	(\$1,637,927)	\$11,071,956
INCOME TAX EXPENSE											
17	Investment/Production Tax Credit	(526,207)	\$0	486,358	\$0	\$0	\$0	(\$1,147,764)	\$3,931	\$0	(\$1,183,682)
18	Deferred Income Taxes	1,317,384	0	0	0	0	0	0	(352,223)	(2,604,630)	(1,639,469)
19	Income Taxes	4,304,133	(2,057,464)	(1,511,539)	(1,457,389)	82,740	290,728	474,830	2,090,485	192,316	2,408,839
20	TOTAL INCOME TAX EXPENSE	\$5,095,310	(\$2,057,464)	(\$1,025,181)	(\$1,457,389)	\$82,740	\$290,728	(\$672,934)	\$1,742,193	(\$2,412,314)	(\$414,312)
21	NET OPERATING INCOME	\$18,454,391	(\$2,915,860)	(\$2,142,169)	(\$2,065,428)	\$117,260	\$412,022	\$672,934	(\$1,821,270)	\$774,387	\$11,486,267
22	Allowance for Funds Used During Construction	0	0	0	0	0	0	0	0	0	0
23	TOTAL AVAILABLE FOR RETURN	\$18,454,391	(\$2,915,860)	(\$2,142,169)	(\$2,065,428)	\$117,260	\$412,022	\$672,934	(\$1,821,270)	\$774,387	\$11,486,267

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
SUMMARY OF REVENUE REQUIREMENTS

Case No. PU-17-398
PART B
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Line No.	Description	(A) Proposed Test Year 2018	(B) Proposed Interim Test Year	Change (B) - (A)
1	Average Rate Base	\$354,191,766	\$223,306,066	(\$130,885,700)
2	Operating Income (Before AFUDC)	\$18,454,391	\$11,486,268	(\$6,968,123)
3	Allowance for Funds Used During Construction (AFUDC)	\$0	\$0	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$18,454,391	\$11,486,268	(\$6,968,123)
5	Overall Rate of Return (Line 4 / Line 1)	5.21%	5.14%	-(0.07)%
6	Required Rate of Return	7.97%	7.96%	-0.01%
7	Operating Income Requirement (Line 1 x Line 6)	\$28,229,084	\$17,775,163	(\$10,453,921)
8	Income Deficiency (Line 7 - Line 4)	\$9,774,693	\$6,288,895	(\$3,485,798)
9	Gross Revenue Conversion Factor	1.60776	1.32284	0
10	Revenue Deficiency (Line 8 x Line 9)	\$15,715,320	\$8,319,184	(\$7,396,136)
11	Retail Related Revenues Under Present Rates	\$148,071,948	\$122,589,268	(\$25,482,680)
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	10.61%	6.79%	(3.83)%

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE (2010)
 DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
 PART C
 Revised Schedule 1
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Line No.	Description	(A) Results of Most Recent General Rate Case PU-08-862	(B) Proposed Interim Test Year	(C) Change (B) - (A)
Utility Plant in Service:				
1	Production	\$154,602,785	\$154,188,768	(\$414,017)
2	Transmission	83,873,091	104,672,321	20,799,230
3	Distribution	140,016,287	228,593,947	88,577,660
4	General	29,250,219	36,081,097	6,830,878
5	Intangible	1,677,249	5,727,482	4,050,233
6	TOTAL Utility Plant in Service	\$409,419,630	\$529,263,615	\$119,843,984
Accumulated Depreciation				
8	Production	(\$86,542,454)	(\$98,334,309)	(\$11,791,855)
9	Transmission	(30,681,969)	(45,254,234)	(14,572,265)
10	Distribution	(59,273,728)	(98,387,399)	(39,113,671)
11	General	(11,712,740)	(13,900,914)	(2,188,174)
12	Intangible	(471,172)	(818,591)	(347,419)
13	TOTAL Accumulated Depreciation	(\$188,682,063)	(\$256,695,448)	(\$68,013,385)
14	NET Utility Plant in Service			
15	Production	\$68,060,331	\$55,854,459	(\$12,205,872)
16	Transmission	53,191,122	59,418,086	6,226,964
17	Distribution	80,742,559	130,206,548	49,463,989
18	General	17,537,479	22,180,183	4,642,704
19	Intangible	1,206,077	4,908,890	3,702,813
20	NET Utility Plant in Service	\$220,737,568	\$272,568,167	\$51,830,599
21				
22	Utility Plant Held for Future Use	12,871	13,044	173
23	Construction Work in Progress	2,246,153	271,747	(1,974,406)
24	Materials and Supplies	5,722,628	7,946,645	2,224,017
25	Fuel Stocks	3,072,173	4,430,805	1,358,632
26	Prepayments	(13,279,546)	(12,739,580)	539,966
27	Customer Advances & Deposits	(54,379)	(353,143)	(298,764)
28	Cash Working Capital	1,485,939	3,548,095	2,062,156
29	Unamortized Rate Case Expense	0		
30	Accumulated Deferred Income Taxes	(32,611,608)	(52,379,715)	(19,768,107)
31	Total Average Rate Base	\$187,331,798	\$223,306,066	\$35,974,267

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
DETAILED RATE BASE COMPONENTS
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 2
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Total Average Rate Base proposed by OTP for interim rates increased by approximately \$36.0 million since the last approved electric rate case in Case No. PU-08-862. As noted earlier, interim rates exclude costs that are not of like-kind and rate base being recovered in OTP's riders during the interim period.

The increase in Average Rate Base is primarily related to the net effect of Utility Plant in Service and Accumulated Deferred Income Taxes. Gross Plant in Service increased by \$119.8 million and Reserve for Depreciation and Amortization increased by \$68.0 million. Total Net Plant in Service increased approximately \$51.8 million. In addition, Accumulated Deferred Income Taxes (ADIT) increased approximately \$19.8 million, which reduces rate base. These components account for approximately \$32.0 million of the \$36.0 million increase to rate base.

Distribution Plant now comprises 47.8 percent of Net Plant compared to 36.6 percent for OTP's Most Recent General Rate Case, increasing distribution plant by \$49.5 million, (capital additions of \$88.6 million offset by increases in depreciation reserves of \$39.1 million).

Transmission Plant increased by \$6.2 million (capital additions of \$20.8 million offset by increases in depreciation reserves of \$14.6 million). Transmission Plant comprises 21.8 percent of Net Plant as compared to 24.1 percent in OTP's Most Recent General Rate Case.

Net Production Plant in Service decreased \$12.2 million since OTP's Most Recent General Rate Case. Production Plant is now 20.5 percent of Plant in Service compared to 30.8 percent in that case.

As mentioned earlier, ADIT, a reduction to Average Rate Base, increased by \$19.8 million due to the impact of accelerated tax depreciation taken on OTP's capital expenditures. This increase is mainly caused by timing differences between book and tax depreciation on plant in service investment.

Cash Working Capital increased approximately \$2.0 million, Materials and Supplies comprised an increase of \$2.2 million, Fuel Inventory increased by \$1.4 million, and Customer Advances and Deposits increased by \$298,764 (reduction to rate base) since OTP's Most Recent General Rate Case.

The net effect of the \$51.8 million increase in Net Plant in Service, the \$19.8 million increase in Accumulated Deferred Income Taxes (a reduction to Average Rate Base), and other components shown in Part C, Schedule 1 account for the \$36.0 million increase in Total Average Rate Base for the interim rate period.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
STATEMENT OF OPERATING INCOME

Case No. PU-17-398
PART C
Revised Schedule 3
Page 1 of 1

Line No.	Description	(A) Results of Most Recent General Rate Case PU-08-862	(B) Proposed Interim Test Year	(C) Change (B) - (A)
<u>OPERATING REVENUES</u>				
1	Retail	\$118,309,177	\$122,589,268	\$4,280,091
2	Other Operating Revenue	5,304,529	9,712,037	4,407,508
3	TOTAL OPERATING REVENUE	\$123,613,706	\$132,301,305	\$8,687,599
<u>OPERATING EXPENSES</u>				
5	Production Expenses	\$62,213,340	\$58,417,943	(\$3,795,397)
6	Transmission Expenses	4,467,061	11,026,754	6,559,693
7	Distribution Expenses	6,727,802	7,680,921	953,119
8	Customer Accounting Expenses	4,728,770	6,091,579	1,362,810
9	Customer Service & Information Expenses	1,027,290	1,382,509	355,220
10	Sales Expenses	251,476	22,472	(229,005)
11	Administration & General Expenses	13,526,788	19,282,795	5,756,007
12	Charitable Contributions	114,816	0	(114,816)
13	Depreciation Expense	10,442,094	13,387,642	2,945,548
14	General Taxes	3,964,363	3,936,734	(27,629)
15	TOTAL OPERATING EXPENSES	\$107,463,801	\$121,229,349	\$13,765,550
16	NET OPERATING INCOME BEFORE INCOME TAXES	\$16,149,905	\$11,071,955	(\$5,077,951)
<u>INCOME TAX EXPENSE</u>				
17	Investment Tax Credit	(\$475,573)	(\$1,183,682)	(\$708,108)
18	Deferred Income Taxes	216,508	(1,639,469)	(1,855,978)
19	Income Taxes	4,132,875	2,408,839	(1,724,036)
20	TOTAL INCOME TAX EXPENSE	\$3,873,810	(\$414,312)	(\$4,288,122)
21	NET OPERATING INCOME	\$12,276,096	\$11,486,268	(\$789,829)
22	Allowance for Funds Used During Construction	0	0	0
23	TOTAL AVAILABLE FOR RETURN	\$12,276,096	\$11,486,268	(\$789,829)

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
STATEMENT OF OPERATING INCOME
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 4
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The Total Available for Return approved by the Commission in OTP's Most Recent General Rate Case compared to the Total Available for Return proposed in the Proposed Interim Test Year shows a decrease of \$0.8 million.

Major components of the change in utility available for return include the following:

Retail Electric Revenues increased by \$4.3 million or 3.6 percent.

Other Revenue increased by \$4.4 million from \$5.3 million in OTP's Most Recent General Rate Case to \$9.7 million in the Proposed Interim Test Year.

Fuel, Purchased Energy and Power Production costs decreased by approximately \$3.8 million compared to OTP's Most Recent General Rate Case.

Other Operating Expenses increased by approximately \$14.7 million. The changes that occurred in the various cost functions are: Transmission expense, an increase of \$6.6 million; Distribution expense, an increase of \$1.0 million; Customer Accounting, an increase of \$1.4 million; Customer Services combined with Information and Sales, an increase of \$0.1 million; and Administrative and General expense, an increase of \$5.8 million.

Depreciation expense increased by approximately \$2.9 million which represents a 28.2 percent increase over OTP's Most Recent General Rate Case.

Investment Tax Credits increased by \$0.7 million while Deferred Income Taxes decreased by \$1.8 million while Income Tax Expense decreased by \$1.7 million resulting in a decrease of approximately \$4.3 in Total Income Taxes since OTP's Most Recent General Rate Case.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
SUMMARY OF REVENUE REQUIREMENTS

Case No. PU-17-398
PART C
Revised Schedule 5
Page 1 of 1

Line No.	Description	(A) Results of Most Recent General Rate Case PU-08-862	(B) Proposed Interim Test Year	(C) Change (B) - (A)
1	Average Rate Base	\$187,331,798	\$223,306,066	\$35,974,268
2	Operating Income (Before AFUDC)	\$12,276,096	\$11,486,268	(\$789,828)
3	Allowance for Funds Used During Construction (AFUDC)	\$0	\$0	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$12,276,096	\$11,486,268	(\$789,828)
5	Overall Rate of Return (Line 4 / Line 1)	6.55%	5.14%	(1.41)%
6	Required Rate of Return	8.62%	7.96%	(0.66)%
7	Operating Income Requirement (Line 1 x Line 6)	\$16,148,001	\$17,775,163	\$1,627,162
8	Income Deficiency (Line 7 - Line 4)	\$3,871,905	\$6,288,895	\$2,416,990
9	Gross Revenue Conversion Factor	1.645413	1.322837	0
10	Revenue Deficiency (Line 8 x Line 9)	\$6,370,885	\$8,319,186	\$1,948,300
11	Retail Related Revenues Under Present Rates	\$118,309,177	\$122,589,268	\$4,280,091
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	5.38%	6.79%	1.40%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
CAPITAL STRUCTURE AND RATE OF RETURN CALCULATIONS

Case No. PU-17-398
PART C
Revised Schedule 6
Page 1 of 1

Line No.	Capitalization:	(A) Amount	(B) % of Total Capitalization	(C) Cost of Capital	(D) Weighted Cost of Capital
I. Capital Structure and Rate of Return Calculation Approved by the Commission in the Most Recent General Rate Case (Case No. PU-08-862)					
1	Long-Term Debt	\$185,725,713	43.1%	6.30%	2.72%
2	Short-Term Debt	0	0.0%	0.00%	0.00%
3	Long-Term and Short-Term Debt	\$185,725,713	43.1%	6.30%	2.72%
4	Preferred Stock	15,500,000	3.597%	4.75%	0.17%
5	Net Common Equity	229,633,133	53.3%	10.75%	5.73%
6	Total Equity	\$245,133,133	56.9%		5.90%
7	Total Capitalization	\$430,858,846	100.00%		8.62%

II. Capital Structure and Rate of Return Calculation for Proposed Interim Rates					
8	Long-Term Debt	\$ 492,672,120	45.8%	5.43%	2.49%
9	Short-Term Debt	18,025,434	1.7%	3.83%	0.06%
10	Long-Term and Short-Term Debt	\$510,697,554	47.5%	5.37%	2.55%
11	Preferred Stock	0	0.0%	0.00%	0.00%
12	Net Common Equity	564,383,902	52.5%	10.30%	5.41%
13	Total Equity	\$564,383,902	52.5%		5.41%
14	Total Capitalization	\$1,075,081,457	100.0%		7.96%

III. Amount of Changes Between I and II

		Amount		Change
		Most Recent General Rate Case Filing	Proposed Interim Rate	(C) = (B) - (A)
		(A)	(B)	
15	Long-Term Debt	\$185,725,713	\$492,672,120	\$306,946,407
16	Short-Term Debt	0	18,025,434	18,025,434
17	Long-Term and Short-Term Debt	\$185,725,713	\$510,697,554	\$324,971,841
18	Preferred Stock	15,500,000	0	(\$15,500,000)
19	Net Common Equity	229,633,133	564,383,902	334,750,769
20	Total Equity	\$245,133,133	\$564,383,902	\$319,250,769
21	Total Capitalization	\$430,858,846	\$1,075,081,457	\$644,222,611

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
CAPITAL STRUCTURE AND RATE OF RETURN CALCULATIONS
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 7
Page 1 of 1

Long-Term Debt in the Proposed Interim Test Year has increased by approximately \$306.9 million, compared to OTP's Most Recent General Rate Case. The increase in Long-Term Debt was necessary to support OTP's capital expenditure plan and maintain an appropriate balance of debt and equity and a balanced capital structure.

The capital structure for Interim Rates includes \$18.0 million of Short-Term Debt as compared to \$0.0 million in OTP's Most Recent General Rate Case.

Common Equity increased by approximately \$319.3 million primarily due to reinvestment of retained earnings and infusions of equity from Otter Tail Corporation to support OTP's capital expenditure plan and provide an appropriate balance of debt and equity and a balanced capital structure.

The overall cost of capital decreased from OTP's Most Recent General Rate Case. The decrease is equally driven by a decrease in the cost of debt and cost of equity. The 10.30 percent cost of common equity is lower than the 10.75 percent cost of common equity in OTP's Most Recent General Rate Case.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
SUMMARY COMPARISON OF OPERATING REVENUE
UNDER PRESENT AND PROPOSED INTERIM RATES FOR THE TEST YEAR

Case No. PU-17-398
PART D
Page 1 of 1
Revised Rate Schedule

<u>Rate Schedule</u>	<u>Operating Revenue</u>			<u>Percent</u>
	<u>Present Revenues</u>	<u>Proposed Interim</u>	<u>Increase</u>	<u>Change</u>
Residential Service	\$34,974,795	\$37,348,263	\$2,373,468	6.79%
Residential Demand Control	\$5,268,890	\$5,626,448	\$357,559	6.79%
Total Residential Class Revenue	\$40,243,684	\$42,974,711	\$2,731,027	6.79%
Farm Service	\$2,055,183	\$2,194,653	\$139,469	6.79%
General Service < 20 kW	\$7,963,977	\$8,504,430	\$540,453	6.79%
General Service >= 20 kW	\$24,590,129	\$26,258,870	\$1,668,741	6.79%
Commercial Time of Use	\$8,085	\$8,633	\$549	
Total GS Class Revenue	\$32,562,190	\$34,771,933	\$2,209,743	6.79%
Large General Service	\$25,832,084	\$27,585,107	\$1,753,023	6.79%
Large General Service Time of Day	\$31,626	\$33,772	\$2,146	6.79%
Real Time Pricing	\$9,342,340	\$9,976,332	\$633,992	6.79%
Large General Service Rider	\$0	\$0	\$0	0.00%
Standby Service	\$12,048	\$12,865	\$818	6.79%
Total LGS Class Revenue	\$35,218,098	\$37,608,078	\$2,389,979	6.79%
Irrigation Services	\$51,061	\$54,527	\$3,465	6.79%
Outdoor Lighting - Energy Only	\$303,294	\$323,876	\$20,582	6.79%
Outdoor Lighting	\$2,209,569	\$2,359,515	\$149,946	6.79%
Total Lighting Class Revenue	\$2,512,863	\$2,683,391	\$170,529	6.79%
Municipal Pumping Service	\$979,983	\$1,046,487	\$66,504	6.79%
Civil Defense - Fire Sirens	\$3,241	\$3,461	\$220	6.79%
Total OPA Class Revenue	\$983,224	\$1,049,948	\$66,724	6.79%
Water Heating, Controlled	\$936,416	\$999,963	\$63,547	6.79%
Interruptible Load >= 80 kW	\$4,764,910	\$5,088,267	\$323,357	6.79%
Interruptible Load < 80 kW	\$1,998,017	\$2,133,607	\$135,590	6.79%
Total Interruptible Class Revenue	\$6,762,927	\$7,221,874	\$458,947	6.79%
Deferred Load Controlled Service	\$859,328	\$917,644	\$58,316	6.79%
Fix Time of Delivery Service	\$404,295	\$431,731	\$27,436	6.79%
Total Def. Ld. Class Revenue	\$1,263,623	\$1,349,375	\$85,752	6.79%
Total	\$122,589,268	\$130,908,453	\$8,319,184	6.79%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
SUMMARY COMPARISON OF OPERATING REVENUE
UNDER CURRENT INTERIM AND PROPOSED INTERIM RATES FOR THE TEST YEAR

Case No. PU-17-398
PART D.1
Page 1 of 1
Rate Schedule

<u>Rate Schedule</u>	<u>Operating Revenue</u>			
	<u>Present Interim</u>	<u>Proposed Interim</u>	<u>Increase</u>	<u>Percent Change</u>
Residential Service	\$38,626,780	\$37,348,263	-\$1,278,517	-3.31%
Residential Demand Control	\$5,819,055	\$5,626,448	-\$192,607	-3.31%
Total Residential Class Revenue	\$44,445,835	\$42,974,711	-\$1,471,124	-3.31%
Farm Service	\$2,269,781	\$2,194,653	-\$75,128	-3.31%
General Service < 20 kW	\$8,795,556	\$8,504,430	-\$291,126	-3.31%
General Service >= 20 kW	\$27,157,772	\$26,258,870	-\$898,902	-3.31%
Commercial Time of Use	\$8,929	\$8,633	-\$296	
Total GS Class Revenue	\$35,962,257	\$34,771,933	-\$1,190,324	-3.31%
Large General Service	\$28,529,409	\$27,585,107	-\$944,302	-3.31%
Large General Service Time of Day	\$34,928	\$33,772	-\$1,156	-3.31%
Real Time Pricing	\$10,317,845	\$9,976,332	-\$341,513	-3.31%
Large General Service Rider	\$0	\$0	\$0	0.00%
Standby Service	\$13,306	\$12,865	-\$441	-3.31%
Total LGS Class Revenue	\$38,895,488	\$37,608,078	-\$1,287,410	-3.31%
Irrigation Services	\$56,393	\$54,527	-\$1,866	-3.31%
Outdoor Lighting - Energy Only	\$334,963	\$323,876	-\$11,087	-3.31%
Outdoor Lighting	\$2,440,287	\$2,359,515	-\$80,772	-3.31%
Total Lighting Class Revenue	\$2,775,250	\$2,683,391	-\$91,859	-3.31%
Municipal Pumping Service	\$1,082,311	\$1,046,487	-\$35,824	-3.31%
Civil Defense - Fire Sirens	\$3,579	\$3,461	-\$118	-3.30%
Total OPA Class Revenue	\$1,085,890	\$1,049,948	-\$35,942	-3.31%
Water Heating, Controlled	\$1,034,194	\$999,963	-\$34,231	-3.31%
Interruptible Load >= 80 kW	\$5,262,450	\$5,088,267	-\$174,183	-3.31%
Interruptible Load < 80 kW	\$2,206,645	\$2,133,607	-\$73,038	-3.31%
Total Interruptible Class Revenue	\$7,469,095	\$7,221,874	-\$247,221	-3.31%
Deferred Load Controlled Service	\$949,057	\$917,644	-\$31,413	-3.31%
Fix Time of Delivery Service	\$446,510	\$431,731	-\$14,779	-3.31%
Total Def. Ld. Class Revenue	\$1,395,567	\$1,349,375	-\$46,192	-3.31%
Total	\$135,389,749	\$130,908,453	-\$4,481,297	-3.31%



RESIDENTIAL SERVICE

DESCRIPTION	RATE CODE
Residential Service	50-101

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to residential service as defined in the General Rules and Regulations.

RATE:

RESIDENTIAL SERVICE				
Customer Charge per Month:	\$8.00			
Monthly Minimum Bill:	Customer Charge			
Energy Charge per kWh:	Summer		Winter	
First 1,000:	8.074	¢/kWh	7.493	¢/kWh
Excess:	8.074	¢/kWh	6.803	¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

**N
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N
N**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.



RESIDENTIAL DEMAND CONTROL SERVICE
(Commonly identified as RDC)

DESCRIPTION	RATE CODE
Residential Demand Control	50-241

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to Residential Customers with approved demand control systems.

RATE:

RESIDENTIAL DEMAND CONTROL SERVICE		
Customer Charge per Month:	\$18.38	
Monthly Minimum Bill:	Customer + Demand Charge	
Energy Charge per kWh:	Summer	Winter
	4.257 ¢/kWh	4.301 ¢/kWh
Demand Charge per kW:	Summer	Winter
	\$6.52 /kW	\$2.63 /kW

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

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Fergus Falls, Minnesota

FARM SERVICE

DESCRIPTION	RATE CODE
Farm Service	50-361

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to general Farm and home use. The Customer may elect to have the following service offerings in the farm home (for residential uses); Residential Service (Section 9.01) or Residential Demand Control Service Schedule (Section 9.02) if all the requirements specified for that schedule are satisfied.

RATE:

FARM SERVICE		
Customer Charge per Month:	\$12.00	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month:		
Single Phase	\$0.00	
Three Phase: Overhead <=25kVA	\$3.37	
Three Phase: Overhead > 25kVA	\$3.93	
Three Phase: Underground <=25kVA	\$9.39	
Three Phase: Underground > 25kVA	\$10.78	
Energy Charge per kWh:	Summer	Winter
First 1600	7.272 ¢/kWh	6.601 ¢/kWh
Excess	6.125 ¢/kWh	5.555 ¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota.

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

EFFECTIVE with bills rendered on
and after ~~January-March~~ 1, 2018, in North

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs

SMALL GENERAL SERVICE
Under 20 kW

DESCRIPTION	RATE CODE
Metered Service under 20 kW – Secondary Service	50-404
Metered Service under 20 kW – Primary Service	50-405

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE			PRIMARY SERVICE	
Customer Charge per Month:	\$13.00		\$13.00	
Monthly Minimum Bill:	Customer Charge		Customer Charge	
Energy Charge per kWh:	Summer	Winter	Summer	Winter
	8.139 ¢/kWh	7.392 ¢/kWh	8.101 ¢/kWh	7.355 ¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota.

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

EFFECTIVE with bills rendered on
and after ~~January-March~~ 1, 2018, in North

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



GENERAL SERVICE
20 kW or Greater

DESCRIPTION	RATE CODE
General Service – Secondary Service	50-401
General Service – Primary Service	50-403

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers, with a measured demand of at least 20 kW within the most recent 12 months. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE		PRIMARY SERVICE								
Customer Charge per Month:	\$12.00	\$12.00								
Monthly Minimum Bill:	Customer + Facilities Charge	Customer + Facilities Charge								
Facilities Charge per Month:	\$0.52/kW	\$0.38/kW								
Energy Charge per kWh:	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.843 ¢/kWh</td> <td style="text-align: center;">7.122 ¢/kWh</td> </tr> </table>	Summer	Winter	7.843 ¢/kWh	7.122 ¢/kWh	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.806 ¢/kWh</td> <td style="text-align: center;">7.086 ¢/kWh</td> </tr> </table>	Summer	Winter	7.806 ¢/kWh	7.086 ¢/kWh
Summer	Winter									
7.843 ¢/kWh	7.122 ¢/kWh									
Summer	Winter									
7.806 ¢/kWh	7.086 ¢/kWh									

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric

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INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the greater of 80 kW or the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be based on the largest of the most recent 12 monthly measured demands.

DETERMINATION OF BILLING DEMAND: The billing demand shall be the greater of 80 kW or the maximum kW as measured by a suitable demand meter for any period of 15 consecutive minutes during the month for which the bill is rendered adjusted for Excess Reactive Demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The billing demand shall be increased by one kW for each whole 10 kvar of measured reactive demand in excess of 50% of the measured demand in kW.

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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TERMS AND CONDITIONS: A Customer with a billing demand of less than 20 kW for 12 consecutive months will have the option to take service under the Small General Service schedule (Section 10.01).

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the applicability matrices of riders.

DEFINITION OF DECLARED, INTERMEDIATE AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

Declared-Peak: Hours declared (see Declared Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

SUMMER SEASON - JUNE 1 THROUGH SEPTEMBER 30 BILLINGS

Declared-Peak: Hours declared (see Declared-Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

DECLARED-PEAK NOTIFICATION: The Company shall make available to Customers, no later than 4:00 p.m. (Central Time) of the preceding day, "declared-peak" designations for the next business day. Except for unusual periods, the Company will make "declared-peak" designations for Saturday through Monday available to Customers on the previous Friday. More than one-day-ahead "declared-peak" designations may also be used for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be the greater of 80 kW or the largest of the most recent 12 monthly measured demands.

METERED AND ESTABLISHED DEMAND: The Metered Demand shall be the maximum kW registered over any period of one hour during the month for which the bill is rendered. The Established Demand shall be the Metered Demand adjusted for excess reactive demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The Metered Demand shall be increased by one kW for each whole ten kVar of reactive demand in excess of 50% of the measured demand in kW.

DEFINITION OF ON-PEAK, SHOULDER AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

On-Peak: For all kW and kWh used Monday through Friday between 7:00 a.m. and 12:00 noon, and between 5:00 p.m. and 9:00 p.m.

Shoulder: For all kW and kWh used Monday through Friday hours 6:00 a.m. to 7:00 a.m., hours 12:00 noon to 5:00 p.m. and hours 9:00 p.m. to 10:00 p.m. and, Saturday through Sunday 6:00 p.m. to 10:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday hours 10:00 p.m. to 9:00 a.m. and, Saturday and Sunday 10:00 p.m. through 9:00 a.m.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

EFFECTIVE with bills rendered on
and after ~~January-March~~ 1, 2018, in North

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
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MANDATORY AND VOLUNTARY RIDERS: The amount of bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DETERMINATION OF METERED DEMAND: Metered Demand shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.

CONTRACT PERIOD: Standby Service is applicable only by signed agreement, setting forth the location and conditions applicable to the electric service, such as the Contracted Backup Demand, type of standby service (Option A or B), excess facilities required for service and other applicable terms and conditions, and providing for an initial minimum contract period of one year, unless otherwise authorized by the Company.

TERMS AND CONDITIONS:

1. The Company's meter will measure power and energy from the Company to the Customer. Any flow of power and energy from the Customer to the Company will be separately metered under one of the Company's Purchase Power Rate Schedules, or by contract.
2. Option A - Firm Standby: Exclusive of any scheduled maintenance hours, if the number of hours on which Backup Service is supplied exceeds 120 On-Peak hours in the Summer season and 240 On-Peak hours in the Winter season, the Customer may be required to take service under a standard, non-standby, rate schedule.
3. Option B – Non-Firm Standby: Backup Service is not available during any On-peak season. This service is only available in the Summer Shoulder and Summer Off-Peak and Winter Shoulder and Winter Off-Peak hours on a non-firm basis. The Company makes no guarantee that this service will be available; however, the Company will make reasonable efforts to provide Backup Service under Option B whenever possible.

OPTION 2				
Customer Charge per Month:	\$5.00			
Monthly Minimum Bill:	Customer + Facilities Charge			
Facilities Charge per Month:	Customer-Specific see Tariff			
Energy Charge per kWh:	Summer		Winter	
Declared-Peak	14.080	¢/kWh	8.390	¢/kWh
Intermediate	5.071	¢/kWh	4.741	¢/kWh
Off-Peak	2.272	¢/kWh	2.242	¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
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FACILITIES CHARGE: Customers served under this rate shall pay an annual fixed charge equal to 18% of the investment of the Company in the extension of lines, including any rebuilding or cost of capacity increase in lines or apparatus necessary because of the irrigation pumping load.

Alternatively, Customers may prepay the installation and cost of the equipment and shall pay an annual fixed charge equal to 3.5% of the investment of the Company, in lieu of the 18% annual fixed charge.

In either option, equipment remains the property of the Company. This charge shall be reviewed if additional Customers are connected to the extension within five years. The annual fixed charge will be billed in seven equal monthly installments May through November of each year.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



RATE – NON-METERED:

**SIGN LIGHTING/OUTDOOR LIGHTING
NON-METERED RATE**
Monthly charge = Connected kW x \$22.58, where Connected kW is the
rated power of the lighting fixture (including ballast).

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

SERVICE CONDITIONS: Company-owned lights shall not be attached to Customer-owned property.

The Company shall have the right to periodically review the Customer’s lighting equipment to verify that the rated power (kW) of the non-metered fixtures is consistent with the Company’s records.



FLOODLIGHTING		
Fixture	Unit Type	Monthly Charge
400 MV-Flood	Mercury Vapor	\$16.78
400 MA-Flood	Metal Additive Mercury	17.91
400 HPS-Flood	High Pressure Sodium	18.32
1000 MV-Flood	Mercury Vapor	29.08
1000 MA-Flood	Metal Additive Mercury	30.74

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Due to the U.S. Government Energy Act of 2005, after July 1, 2008, the Company will no longer install Mercury Vapor fixtures for new installations.

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

SEASONAL CUSTOMERS: Seasonal Customers will be billed at the same rate as year-around Customers, except as follows:

A fixed charge of \$10.80 will be billed each seasonal Customer once per season per fixture in addition to the rate provided above. The fixed charge will be included in the first bill rendered for each season.

Each Customer will be billed for the number of months each season that the outdoor lighting fixture is in use, but not less than a minimum of four months, plus the seasonal fixed charge.

UNDERGROUND SERVICE: If a Customer requests underground service to any outdoor lighting unit or sign, the Company will supply a span of up to 200 feet of wire and add an additional \$1.96 to the monthly rate specified above. If overhead service is not available, there is no additional charge. **There is no additional charge for the MV-6PT, HPS-9PT, or the HPS-14PT fixtures.**



PRIMARY SERVICE			
Customer Charge per Month:	\$4.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$2.68		
Energy Charge per kWh:	Summer	Winter	
	6.124 ¢/kWh	5.552 ¢/kWh	

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INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.



Fergus Falls, Minnesota

CIVIL DEFENSE - FIRE SIRENS

DESCRIPTION	RATE CODE
Civil Defense – Fire Sirens	50-843

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to separately served civil defense and municipal fire sirens.

RATE:

CIVIL DEFENSE - FIRE SIRENS	
Customer Charge per Month:	\$1.00
Monthly Minimum Bill:	Customer Charge
Facilities Charge per Month:	\$0.00
Charge per HP:	53.193¢/HP

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

OTHER SIREN SERVICE: If the siren is served through a tariff applicable to the City Hall, fire hall or other tariffed service, no separate billing shall be made for the siren.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

EFFECTIVE with bills rendered
on and after ~~January~~March 1, 2018, in North

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



SMALL POWER PRODUCER RIDER
OCCASIONAL DELIVERY ENERGY SERVICE
(Commonly identified as Net Energy Billing)

Base Avoided Costs Code 50-9020
Base Avoided Costs plus Renewable Energy Credit Code 50-9021

AVAILABILITY: Available to any qualifying facility not exceeding 100 kW of generating capacity.

METERING CHARGE: \$1.40 per month

PAYMENT SCHEDULES: Base Avoided Costs: 2.392¢ per kWh

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Base Avoided Costs plus Renewable Energy Credit: 2.452¢ per kWh

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SPECIAL CONDITIONS OF SERVICE: The Customer will be required to sign a contract, agreeing to terms and conditions specified for small power producers. The minimum term of the contract is 12 months.

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern service of this schedule.

INTERIM RATE ADJUSTMENT:

A 10.446.79 percent increase will be added to the Metering Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



**SMALL POWER PRODUCER RIDER
TIME OF DELIVERY ENERGY SERVICE**

Base Avoided On-Peak Costs	Code 50-9030
Base Avoided Off-Peak Costs	Code 50-9031
Base Avoided On-Peak Costs Plus Renewable Energy Credit	Code 50-9032
Base Avoided Off-Peak Costs Plus Renewable Energy Credit	Code 50-9033

AVAILABILITY: This rider is available to any Qualifying Facility not exceeding 100 kW of generating capacity. This rider is available to any Qualifying Facility exceeding 100 kW upon the approval of the Company. The Company reserves the right to require the Qualifying Facility to sign an Agreement.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

Base Avoided Costs	<u>On-Peak 50-9030</u>	<u>Off-Peak 50-9031</u>	
Summer	2.826¢ per kWh	1.779¢ per kWh	<u>R</u>
Winter	2.919¢ per kWh	2.004¢ per kWh	<u>R</u>
Base Avoided Costs			
Plus Renewable Energy Credit	<u>On-Peak 50-9032</u>	<u>Off-Peak 50-9033</u>	
Summer	2.886¢ per kWh	1.839¢ per kWh	<u>R</u>
Winter	2.979¢ per kWh	2.064¢ per kWh	<u>R</u>

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the Metering Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



**SMALL POWER PRODUCER RIDER
DEPENDABLE SERVICE**

Base Avoided On-Peak Costs	Code 50-9040
Base Avoided Off-Peak Costs	Code 50-9041
Base Avoided On-Peak Costs Plus Renewable Energy Credit	Code 50-9042
Base Avoided Off-Peak Costs Plus Renewable Energy Credit	Code 50-9043

AVAILABILITY: Available to any qualifying facility which is capable of delivering power and energy to the Company on a dependable basis.

INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the Metering Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

Base Avoided Costs	<u>On-Peak 50-9040</u>	<u>Off-Peak 50-9041</u>	
Summer	2.826¢ per kWh	1.779¢ per kWh	R
Winter	2.919¢ per kWh	2.004¢ per kWh	R

Base Avoided Costs Plus Renewable Energy Credit	<u>On-Peak 50-9042</u>	<u>Off-Peak 50-9043</u>	
Summer	2.886¢ per kWh	1.839¢ per kWh	R
Winter	2.979¢ per kWh	2.064¢ per kWh	R

CAPACITY:

	Monthly \$/kW	Monthly \$/kW	
Contract	Net Capacity	Levelized	
<u>Term</u>	<u>Rate</u>	<u>Rate</u>	
60 mos.	\$5.86	\$2.34	R



Fergus Falls, Minnesota

RENEWABLE RESOURCE COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	50-520

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern use of this schedule.

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s Retail Rate Schedules in Section 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

COST RECOVERY CHARGE: There shall be included on each North Dakota customer’s monthly bill a Renewable Resource Cost Recovery (“RRC”) charge based on the applicable cost recovery factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The RRC charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company’s electric service, except Section 13.05 (Economic Development Cost Removal Rider). The following charges are applicable in addition to all charges for service being taken under the Company’s standard rate schedules and will be included in the Energy and Renewable Adjustment line item on the customer’s bill.

Renewable Resource Cost Recovery Factor - 7.7567.493 percent
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DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor*. The forecasted RRC Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The RRC Factor shall be rounded to the nearest 0.001 percent.

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to any electric service under all of the Company's retail rate schedules.

COST RECOVERY FACTOR: There shall be included on each North Dakota Customer's monthly bill a Transmission Cost Recovery charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:		kWh	kW
Large General Service	(a)	N/A ¢/kWh	\$1.739 <u>1.632</u>
Controlled Service	(b)	0.094 <u>0.085</u> ¢/kWh	N/A
Lighting	(c)	0.332 <u>0.312</u> ¢/kWh	N/A
All Other Service		0.578 <u>0.543</u> ¢/kWh	N/A
(a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service Rider. (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load, and 14.07 Fixed Time of Delivery (c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting			

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NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota

Case No. PU-17-~~340~~ 398

Approved by order dated: ~~November 29, 2017~~

EFFECTIVE with bills rendered on
and after ~~January-March~~ March 1, 2018, in North

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

ENVIRONMENTAL COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Service – Environmental Cost Recovery	50-570
All Service – Reagent and Allowance Cost Recovery	50-572

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider consists of two separate charges; the Environmental Cost Recovery (“ECR”) Rider Charge and the Reagents and Emissions Allowance Adjustment (“REAA”) Rider Charge. This rider is applicable to electric service under all of the Company’s retail rate schedules in Sections 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer’s monthly bill an Environmental Cost Recovery (“ECR”) Charge, based on the applicable ECR Factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The ECR Factor will not apply to any Mandatory Riders, except Section 13.05 (Economic Development Cost Removal Rider). The ECR charge will be included as part of the charge reflected on the Customer’s bill on the line labeled “EPA Req Environmental Cst.”

Environmental Cost Recovery Factor - <u>6.6295.993</u> percent

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DETERMINATION OF ECR FACTOR: The ECR Factor shall be determined by dividing the forecasted *balance of the ECR Tracker account* by the *forecasted retail revenues subject to the ECR Factor*. The forecasted ECR Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The ECR Factor shall be rounded to the nearest 0.001 percent.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by Order dated ~~December 20, 2017~~
Bruce G. Gerhardson

EFFECTIVE with bills rendered on
and after ~~January~~March-1, 2018, in North

APPROVED:

Vice President, Regulatory Affairs



Fergus Falls, Minnesota

WATER HEATING CONTROL RIDER

Table with 2 columns: DESCRIPTION, RATE CODE. Rows include Separately Metered Water Heating Control Service (50-191) and Water Heating Credit Control Service (50-192).

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

AVAILABILITY: This rider is available for residential or nonresidential purposes.

RATE:

Table titled WATER HEATING - CONTROLLED SERVICE 191. Includes Customer Charge per Month (\$1.00), Monthly Minimum Bill (Customer + Facilities Charge), Facilities Charge per Month (\$1.00), and Energy Charge per kWh (Summer: 5.403 ¢/kWh, Winter: 5.268 ¢/kWh).

Table titled WATER HEATING CREDIT 192. Text: A \$4.00 credit per month shall be applied to all bills having direct control water heating, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Bill.

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the

NORTH DAKOTA PUBLIC SERVICE COMMISSION Dakota Case No. PU-17-398 Approved by order dated ~~December 20, 2017~~

EFFECTIVE with bills rendered on and after ~~January-March~~ 1, 2018, in North

APPROVED: Bruce G. Gerhardson Vice President, Regulatory Affairs



REAL TIME PRICING RIDER

DESCRIPTION	RATE CODE
Transmission Service	50-660
Primary Service	50-662
Secondary Service	50-664

RULES AND REGULATIONS: Terms and condition of this tariff and the General Rules and Regulations govern use of this schedule.

INTERIM RATE ADJUSTMENT: A ~~10.44~~6.79 percent increase will be added to the Administrative Charge.

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AVAILABILITY: This rider is available on a voluntary basis to Customers who have maintained a measured demand of at least 200 kW during the historical period used for Customer Baseline Load (“CBL”) development. Priority will be established based on the date that an agreement is executed by both the Customer and the Company.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of \$199.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges.

TYPE OF SERVICE: Three-phase, 60 hertz at any available Standard Voltage.

TERM OF SERVICE: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement with the Company or by entering into amendments of existing electric service agreements. A Customer who voluntarily cancels service under this rider is not eligible to receive service again under this rider for a period of one year.



LARGE GENERAL SERVICE RIDER

DESCRIPTION	Option 1	Option 2
Fixed Rate Energy Pricing	50-648	50-649
System Marginal Energy Pricing	50-642	50-645
Short-term Marginal Capacity Purchases	50-643	50-646
Short-term Marginal Capacity Releases	50-644	50-647

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

AVAILABILITY: This rider is available at the request of Customers who take service under the rate schedules listed in the Application Section of this tariff and have either (**Option 1**) a metered Demand of at least 1 MW, or (**Option 2**) a Total Coincident Demand of at least 10 MW for multiple, non-contiguous facilities that function in series.

INTERIM RATE ADJUSTMENT: A ~~10.44~~6.79 percent increase will be added to the Administrative Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

ELECTRIC SERVICE AGREEMENT: For service under this Rider, the Company may, at its discretion, require a written electric service agreement (ESA”) between the Company and the Customer that sets forth, among other things, the Customer’s Billing Demand, Firm Demand, On-Peak Baseline Demand and Off-Peak Baseline Demand.

FIXED RATE ENERGY PRICING:

Background: Certain Company industrial and commercial Customers have ESAs that designate, among other things, a Billing Demand, On-Peak and Off-Peak Baseline Demands and a Firm Demand. With On-Peak and Off-Peak Baseline Demands, the Company agrees to provide and the Customer agrees to purchase all of its Energy requirements at rates set forth in the Customer’s applicable rate schedule and/or a negotiated rate subject to Commission approval. Setting a Firm and Baseline Demands benefits both the Company and the Customer. With Firm Demands, the Company is able to curtail participating Customers’ load to predetermined levels which allows the Company to more accurately forecast its native load Capacity and Energy requirements.



INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

PENALTY PERIODS – OPTION 1 ONLY: Penalty periods are defined as periods when the Company signals to interrupt the Customer’s load and the Customer’s equipment does not shed the load. Installation of a dual register meter will be at the option of the Company. When a dual register meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register meters.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Short-duration cycling is approximately 15 minutes off / 15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30). Domestic water heating may be controlled up to 14 hours in the 24-hour period.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand shall be based on the greatest of the current and preceding 11 monthly measured demands.

DETERMINATION OF CONTROL PERIOD DEMAND – OPTION 2 ONLY: The billing demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.



RATE:

CONTROLLED SERVICE - INTERR LOAD – SELF-CONTAINED			
Customer Charge per Month:	\$2.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$5.00		
	Summer		Winter
Energy Charge per kWh:	3.289 ¢/kWh		3.081 ¢/kWh
Penalty	38.606 ¢/kWh		12.924 ¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.44~~6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer’s load and the Customer’s equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hour during any 24-

RATE:

CONTROLLED SERVICE - DEFERRED LOAD			
Customer Charge per Month:	\$3.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$4.00		
	Summer		Winter
Energy Charge per kWh:	4.784 ¢/kWh		4.632 ¢/kWh
Penalty	33.802 ¢/kWh		11.510 ¢/kWh

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INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.



FIXED TIME OF DELIVERY SERVICE - CT Metering			
Customer Charge per Month:	\$1.50		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$19.00		
	Summer		Winter
Energy Charge per kWh:	2.404 ¢/kWh		2.567 ¢/kWh
Penalty:	9.400 ¢/kWh		7.385 ¢/kWh

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FIXED TIME OF DELIVERY SERVICE – Primary CT Metering			
Customer Charge per Month:	\$3.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$9.00		
	Summer		Winter
Energy Charge per kWh:	2.393 ¢/kWh		2.556 ¢/kWh
Penalty:	9.389 ¢/kWh		7.374 ¢/kWh

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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N

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

- Summer: June 1 through September 30.
- Winter: October 1 through May 31.

RESIDENTIAL SERVICE

DESCRIPTION	RATE CODE
Residential Service	50-101

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to residential service as defined in the General Rules and Regulations.

RATE:

RESIDENTIAL SERVICE				
Customer Charge per Month:	\$8.00			
Monthly Minimum Bill:	Customer Charge			
Energy Charge per kWh:	Summer		Winter	
First 1,000:	8.074	¢/kWh	7.493	¢/kWh
Excess:	8.074	¢/kWh	6.803	¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

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MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.



RESIDENTIAL DEMAND CONTROL SERVICE
(Commonly identified as RDC)

DESCRIPTION	RATE CODE
Residential Demand Control	50-241

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to Residential Customers with approved demand control systems.

RATE:

RESIDENTIAL DEMAND CONTROL SERVICE		
Customer Charge per Month:	\$18.38	
Monthly Minimum Bill:	Customer + Demand Charge	
Energy Charge per kWh:	Summer	Winter
	4.257 ¢/kWh	4.301 ¢/kWh
Demand Charge per kW:	Summer	Winter
	\$6.52 /kW	\$2.63 /kW

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



Fergus Falls, Minnesota

FARM SERVICE

DESCRIPTION	RATE CODE
Farm Service	50-361

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to general Farm and home use. The Customer may elect to have the following service offerings in the farm home (for residential uses); Residential Service (Section 9.01) or Residential Demand Control Service Schedule (Section 9.02) if all the requirements specified for that schedule are satisfied.

RATE:

FARM SERVICE		
Customer Charge per Month:	\$12.00	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month:		
Single Phase	\$0.00	
Three Phase: Overhead <=25kVA	\$3.37	
Three Phase: Overhead > 25kVA	\$3.93	
Three Phase: Underground <=25kVA	\$9.39	
Three Phase: Underground > 25kVA	\$10.78	
Energy Charge per kWh:	Summer	Winter
First 1600	7.272 ¢/kWh	6.601 ¢/kWh
Excess	6.125 ¢/kWh	5.555 ¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

SMALL GENERAL SERVICE
Under 20 kW

DESCRIPTION	RATE CODE
Metered Service under 20 kW – Secondary Service	50-404
Metered Service under 20 kW – Primary Service	50-405

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE			PRIMARY SERVICE	
Customer Charge per Month:	\$13.00		\$13.00	
Monthly Minimum Bill:	Customer Charge		Customer Charge	
Energy Charge per kWh:	Summer	Winter	Summer	Winter
	8.139 ¢/kWh	7.392 ¢/kWh	8.101 ¢/kWh	7.355 ¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.



GENERAL SERVICE
20 kW or Greater

DESCRIPTION	RATE CODE
General Service – Secondary Service	50-401
General Service – Primary Service	50-403

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers, with a measured demand of at least 20 kW within the most recent 12 months. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE		PRIMARY SERVICE								
Customer Charge per Month:	\$12.00	\$12.00								
Monthly Minimum Bill:	Customer + Facilities Charge	Customer + Facilities Charge								
Facilities Charge per Month:	\$0.52/kW	\$0.38/kW								
Energy Charge per kWh:	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.843 ¢/kWh</td> <td style="text-align: center;">7.122 ¢/kWh</td> </tr> </table>	Summer	Winter	7.843 ¢/kWh	7.122 ¢/kWh	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.806 ¢/kWh</td> <td style="text-align: center;">7.086 ¢/kWh</td> </tr> </table>	Summer	Winter	7.806 ¢/kWh	7.086 ¢/kWh
Summer	Winter									
7.843 ¢/kWh	7.122 ¢/kWh									
Summer	Winter									
7.806 ¢/kWh	7.086 ¢/kWh									

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. **R**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the greater of 80 kW or the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be based on the largest of the most recent 12 monthly measured demands.

DETERMINATION OF BILLING DEMAND: The billing demand shall be the greater of 80 kW or the maximum kW as measured by a suitable demand meter for any period of 15 consecutive minutes during the month for which the bill is rendered adjusted for Excess Reactive Demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The billing demand shall be increased by one kW for each whole 10 kvar of measured reactive demand in excess of 50% of the measured demand in kW.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. **R**

TERMS AND CONDITIONS: A Customer with a billing demand of less than 20 kW for 12 consecutive months will have the option to take service under the Small General Service schedule (Section 10.01).

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the applicability matrices of riders.

DEFINITION OF DECLARED, INTERMEDIATE AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

Declared-Peak: Hours declared (see Declared Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

SUMMER SEASON - JUNE 1 THROUGH SEPTEMBER 30 BILLINGS

Declared-Peak: Hours declared (see Declared-Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

DECLARED-PEAK NOTIFICATION: The Company shall make available to Customers, no later than 4:00 p.m. (Central Time) of the preceding day, "declared-peak" designations for the next business day. Except for unusual periods, the Company will make "declared-peak" designations for Saturday through Monday available to Customers on the previous Friday. More than one-day-ahead "declared-peak" designations may also be used for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. **R**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be the greater of 80 kW or the largest of the most recent 12 monthly measured demands.

METERED AND ESTABLISHED DEMAND: The Metered Demand shall be the maximum kW registered over any period of one hour during the month for which the bill is rendered. The Established Demand shall be the Metered Demand adjusted for excess reactive demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The Metered Demand shall be increased by one kW for each whole ten kVar of reactive demand in excess of 50% of the measured demand in kW.

DEFINITION OF ON-PEAK, SHOULDER AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

On-Peak: For all kW and kWh used Monday through Friday between 7:00 a.m. and 12:00 noon, and between 5:00 p.m. and 9:00 p.m.

Shoulder: For all kW and kWh used Monday through Friday hours 6:00 a.m. to 7:00 a.m., hours 12:00 noon to 5:00 p.m. and hours 9:00 p.m. to 10:00 p.m. and, Saturday through Sunday 6:00 p.m. to 10:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday hours 10:00 p.m. to 9:00 a.m. and, Saturday and Sunday 10:00 p.m. through 9:00 a.m.



INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DETERMINATION OF METERED DEMAND: Metered Demand shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.

CONTRACT PERIOD: Standby Service is applicable only by signed agreement, setting forth the location and conditions applicable to the electric service, such as the Contracted Backup Demand, type of standby service (Option A or B), excess facilities required for service and other applicable terms and conditions, and providing for an initial minimum contract period of one year, unless otherwise authorized by the Company.

TERMS AND CONDITIONS:

1. The Company's meter will measure power and energy from the Company to the Customer. Any flow of power and energy from the Customer to the Company will be separately metered under one of the Company's Purchase Power Rate Schedules, or by contract.
2. Option A - Firm Standby: Exclusive of any scheduled maintenance hours, if the number of hours on which Backup Service is supplied exceeds 120 On-Peak hours in the Summer season and 240 On-Peak hours in the Winter season, the Customer may be required to take service under a standard, non-standby, rate schedule.
3. Option B – Non-Firm Standby: Backup Service is not available during any On-peak season. This service is only available in the Summer Shoulder and Summer Off-Peak and Winter Shoulder and Winter Off-Peak hours on a non-firm basis. The Company makes no guarantee that this service will be available; however, the Company will make reasonable efforts to provide Backup Service under Option B whenever possible.

OPTION 2				
Customer Charge per Month:	\$5.00			
Monthly Minimum Bill:	Customer + Facilities Charge			
Facilities Charge per Month:	Customer-Specific see Tariff			
Energy Charge per kWh:	Summer		Winter	
Declared-Peak	14.080	¢/kWh	8.390	¢/kWh
Intermediate	5.071	¢/kWh	4.741	¢/kWh
Off-Peak	2.272	¢/kWh	2.242	¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

FACILITIES CHARGE: Customers served under this rate shall pay an annual fixed charge equal to 18% of the investment of the Company in the extension of lines, including any rebuilding or cost of capacity increase in lines or apparatus necessary because of the irrigation pumping load.

Alternatively, Customers may prepay the installation and cost of the equipment and shall pay an annual fixed charge equal to 3.5% of the investment of the Company, in lieu of the 18% annual fixed charge.

In either option, equipment remains the property of the Company. This charge shall be reviewed if additional Customers are connected to the extension within five years. The annual fixed charge will be billed in seven equal monthly installments May through November of each year.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



RATE – NON-METERED:

<p>SIGN LIGHTING/OUTDOOR LIGHTING NON-METERED RATE</p> <p>Monthly charge = Connected kW x \$22.58, where Connected kW is the rated power of the lighting fixture (including ballast).</p>
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INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

SERVICE CONDITIONS: Company-owned lights shall not be attached to Customer-owned property.

The Company shall have the right to periodically review the Customer's lighting equipment to verify that the rated power (kW) of the non-metered fixtures is consistent with the Company's records.

FLOODLIGHTING		
Fixture	Unit Type	Monthly Charge
400 MV-Flood	Mercury Vapor	\$16.78
400 MA-Flood	Metal Additive Mercury	17.91
400 HPS-Flood	High Pressure Sodium	18.32
1000 MV-Flood	Mercury Vapor	29.08
1000 MA-Flood	Metal Additive Mercury	30.74

Due to the U.S. Government Energy Act of 2005, after July 1, 2008, the Company will no longer install Mercury Vapor fixtures for new installations.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

SEASONAL CUSTOMERS: Seasonal Customers will be billed at the same rate as year-around Customers, except as follows:

A fixed charge of \$10.80 will be billed each seasonal Customer once per season per fixture in addition to the rate provided above. The fixed charge will be included in the first bill rendered for each season.

Each Customer will be billed for the number of months each season that the outdoor lighting fixture is in use, but not less than a minimum of four months, plus the seasonal fixed charge.

UNDERGROUND SERVICE: If a Customer requests underground service to any outdoor lighting unit or sign, the Company will supply a span of up to 200 feet of wire and add an additional \$1.96 to the monthly rate specified above. If overhead service is not available, there is no additional charge. **There is no additional charge for the MV-6PT, HPS-9PT, or the HPS-14PT fixtures.**

PRIMARY SERVICE		
Customer Charge per Month:		\$4.00
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month:		\$2.68
Energy Charge per kWh:	Summer	Winter
	6.124 ¢/kWh	5.552 ¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.



Fergus Falls, Minnesota

CIVIL DEFENSE - FIRE SIRENS

DESCRIPTION	RATE CODE
Civil Defense – Fire Sirens	50-843

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

APPLICATION OF SCHEDULE: This schedule is applicable to separately served civil defense and municipal fire sirens.

RATE:

CIVIL DEFENSE - FIRE SIRENS	
Customer Charge per Month:	\$1.00
Monthly Minimum Bill:	Customer Charge
Facilities Charge per Month:	\$0.00
Charge per HP:	53.193¢/HP

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

OTHER SIREN SERVICE: If the siren is served through a tariff applicable to the City Hall, fire hall or other tariffed service, no separate billing shall be made for the siren.



**SMALL POWER PRODUCER RIDER
OCCASIONAL DELIVERY ENERGY SERVICE**
(Commonly identified as Net Energy Billing)

Base Avoided Costs Code 50-9020
Base Avoided Costs plus Renewable Energy Credit Code 50-9021

AVAILABILITY: Available to any qualifying facility not exceeding 100 kW of generating capacity.

METERING CHARGE: \$1.40 per month

PAYMENT SCHEDULES: Base Avoided Costs: 2.392¢ per kWh

Base Avoided Costs plus Renewable Energy Credit: 2.452¢ per kWh

SPECIAL CONDITIONS OF SERVICE: The Customer will be required to sign a contract, agreeing to terms and conditions specified for small power producers. The minimum term of the contract is 12 months.

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern service of this schedule.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



**SMALL POWER PRODUCER RIDER
 TIME OF DELIVERY ENERGY SERVICE**

Base Avoided On-Peak Costs	Code 50-9030
Base Avoided Off-Peak Costs	Code 50-9031
Base Avoided On-Peak Costs Plus Renewable Energy Credit	Code 50-9032
Base Avoided Off-Peak Costs Plus Renewable Energy Credit	Code 50-9033

AVAILABILITY: This rider is available to any Qualifying Facility not exceeding 100 kW of generating capacity. This rider is available to any Qualifying Facility exceeding 100 kW upon the approval of the Company. The Company reserves the right to require the Qualifying Facility to sign an Agreement.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

Base Avoided Costs	<u>On-Peak 50-9030</u>	<u>Off-Peak 50-9031</u>
Summer	2.826¢ per kWh	1.779¢ per kWh
Winter	2.919¢ per kWh	2.004¢ per kWh

Base Avoided Costs		
Plus Renewable Energy Credit	<u>On-Peak 50-9032</u>	<u>Off-Peak 50-9033</u>
Summer	2.886¢ per kWh	1.839¢ per kWh
Winter	2.979¢ per kWh	2.064¢ per kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.



**SMALL POWER PRODUCER RIDER
 DEPENDABLE SERVICE**

Base Avoided On-Peak Costs	Code 50-9040
Base Avoided Off-Peak Costs	Code 50-9041
Base Avoided On-Peak Costs Plus Renewable Energy Credit	Code 50-9042
Base Avoided Off-Peak Costs Plus Renewable Energy Credit	Code 50-9043

AVAILABILITY: Available to any qualifying facility which is capable of delivering power and energy to the Company on a dependable basis.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

Base Avoided Costs	<u>On-Peak 50-9040</u>	<u>Off-Peak 50-9041</u>
Summer	2.826¢ per kWh	1.779¢ per kWh
Winter	2.919¢ per kWh	2.004¢ per kWh
Base Avoided Costs Plus Renewable Energy Credit	<u>On-Peak 50-9042</u>	<u>Off-Peak 50-9043</u>
Summer	2.886¢ per kWh	1.839¢ per kWh
Winter	2.979¢ per kWh	2.064¢ per kWh

CAPACITY:

	Monthly \$/kW	Monthly \$/kW
Contract	Net Capacity	Levelized
<u>Term</u>	<u>Rate</u>	<u>Rate</u>
60 mos.	\$5.86	\$2.34



Fergus Falls, Minnesota

RENEWABLE RESOURCE COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	50-520

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern use of this schedule.

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s Retail Rate Schedules in Section 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

COST RECOVERY CHARGE: There shall be included on each North Dakota customer’s monthly bill a Renewable Resource Cost Recovery (“RRC”) charge based on the applicable cost recovery factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The RRC charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company’s electric service, except Section 13.05 (Economic Development Cost Removal Rider). The following charges are applicable in addition to all charges for service being taken under the Company’s standard rate schedules and will be included in the Energy and Renewable Adjustment line item on the customer’s bill.

Renewable Resource Cost Recovery Factor - 7.493 percent
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R

DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor*. The forecasted RRC Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The RRC Factor shall be rounded to the nearest 0.001 percent.

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to any electric service under all of the Company's retail rate schedules.

COST RECOVERY FACTOR: There shall be included on each North Dakota Customer's monthly bill a Transmission Cost Recovery charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:		kWh	kW
Large General Service (a)		N/A ¢/kWh	\$1.632
Controlled Service (b)		0.085 ¢/kWh	N/A
Lighting (c)		0.312 ¢/kWh	N/A
All Other Service		0.543 ¢/kWh	N/A

(a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service Rider.
 (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load, and 14.07 Fixed Time of Delivery
 (c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting

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Fergus Falls, Minnesota

ENVIRONMENTAL COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Service – Environmental Cost Recovery	50-570
All Service – Reagent and Allowance Cost Recovery	50-572

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider consists of two separate charges; the Environmental Cost Recovery (“ECR”) Rider Charge and the Reagents and Emissions Allowance Adjustment (“REAA”) Rider Charge. This rider is applicable to electric service under all of the Company’s retail rate schedules in Sections 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer’s monthly bill an Environmental Cost Recovery (“ECR”) Charge, based on the applicable ECR Factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The ECR Factor will not apply to any Mandatory Riders, except Section 13.05 (Economic Development Cost Removal Rider). The ECR charge will be included as part of the charge reflected on the Customer’s bill on the line labeled “EPA Req Environmental Cst.”

Environmental Cost Recovery Factor - 5.993 percent

R

DETERMINATION OF ECR FACTOR: The ECR Factor shall be determined by dividing the forecasted *balance of the ECR Tracker account* by the *forecasted retail revenues subject to the ECR Factor*. The forecasted ECR Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The ECR Factor shall be rounded to the nearest 0.001 percent.

The *balance of the ECR Tracker account* for determination of the ECR Factor shall include annual revenue requirements and any true-up balance described as follows:

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by Order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

WATER HEATING CONTROL RIDER

DESCRIPTION	RATE CODE
Separately Metered Water Heating Control Service	50-191
Water Heating Credit Control Service	50-192

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

AVAILABILITY: This rider is available for residential or nonresidential purposes.

RATE:

WATER HEATING - CONTROLLED SERVICE 191		
Customer Charge per Month:	\$1.00	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month:	\$1.00	
Energy Charge per kWh:	Summer	Winter
	5.403 ¢/kWh	5.268 ¢/kWh

WATER HEATING CREDIT 192
A \$4.00 credit per month shall be applied to all bills having direct control water heating, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Bill.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS:

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



REAL TIME PRICING RIDER

DESCRIPTION	RATE CODE
Transmission Service	50-660
Primary Service	50-662
Secondary Service	50-664

RULES AND REGULATIONS: Terms and condition of this tariff and the General Rules and Regulations govern use of this schedule.

INTERIM RATE ADJUSTMENT: A 6.79 percent increase will be added to the Administrative Charge.

R

AVAILABILITY: This rider is available on a voluntary basis to Customers who have maintained a measured demand of at least 200 kW during the historical period used for Customer Baseline Load (“CBL”) development. Priority will be established based on the date that an agreement is executed by both the Customer and the Company.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of \$199.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges.

TYPE OF SERVICE: Three-phase, 60 hertz at any available Standard Voltage.

TERM OF SERVICE: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement with the Company or by entering into amendments of existing electric service agreements. A Customer who voluntarily cancels service under this rider is not eligible to receive service again under this rider for a period of one year.

LARGE GENERAL SERVICE RIDER

DESCRIPTION	Option 1	Option 2
Fixed Rate Energy Pricing	50-648	50-649
System Marginal Energy Pricing	50-642	50-645
Short-term Marginal Capacity Purchases	50-643	50-646
Short-term Marginal Capacity Releases	50-644	50-647

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule.

AVAILABILITY: This rider is available at the request of Customers who take service under the rate schedules listed in the Application Section of this tariff and have either (**Option 1**) a metered Demand of at least 1 MW, or (**Option 2**) a Total Coincident Demand of at least 10 MW for multiple, non-contiguous facilities that function in series.

INTERIM RATE ADJUSTMENT: A 6.79 percent increase will be added to the Administrative Charge. **R**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

ELECTRIC SERVICE AGREEMENT: For service under this Rider, the Company may, at its discretion, require a written electric service agreement (ESA”) between the Company and the Customer that sets forth, among other things, the Customer’s Billing Demand, Firm Demand, On-Peak Baseline Demand and Off-Peak Baseline Demand.

FIXED RATE ENERGY PRICING:

Background: Certain Company industrial and commercial Customers have ESAs that designate, among other things, a Billing Demand, On-Peak and Off-Peak Baseline Demands and a Firm Demand. With On-Peak and Off-Peak Baseline Demands, the Company agrees to provide and the Customer agrees to purchase all of its Energy requirements at rates set forth in the Customer’s applicable rate schedule and/or a negotiated rate subject to Commission approval. Setting a Firm and Baseline Demands benefits both the Company and the Customer. With Firm Demands, the Company is able to curtail participating Customers’ load to predetermined levels which allows the Company to more accurately forecast its native load Capacity and Energy requirements. Baseline Demands assure the Customer a fixed price for Energy up to the Baseline Demand and



INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS – OPTION 1 ONLY: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Installation of a dual register meter will be at the option of the Company. When a dual register meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register meters.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Short-duration cycling is approximately 15 minutes off / 15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30). Domestic water heating may be controlled up to 14 hours in the 24-hour period.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand shall be based on the greatest of the current and preceding 11 monthly measured demands.

DETERMINATION OF CONTROL PERIOD DEMAND – OPTION 2 ONLY: The billing demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.



RATE:

CONTROLLED SERVICE - INTERR LOAD – SELF-CONTAINED			
Customer Charge per Month:	\$2.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$5.00		
	Summer		Winter
Energy Charge per kWh:	3.289 ¢/kWh		3.081 ¢/kWh
Penalty	38.606 ¢/kWh		12.924 ¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer’s load and the Customer’s equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hour during any 24-

RATE:

CONTROLLED SERVICE - DEFERRED LOAD			
Customer Charge per Month:			\$3.00
Monthly Minimum Bill:		Customer + Facilities Charge	
Facilities Charge per Month:			\$4.00
		Summer	Winter
Energy Charge per kWh:		4.784 ¢/kWh	4.632 ¢/kWh
Penalty		33.802 ¢/kWh	11.510 ¢/kWh

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

FIXED TIME OF DELIVERY SERVICE - CT Metering			
Customer Charge per Month:	\$1.50		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$19.00		
	Summer	Winter	
Energy Charge per kWh:	2.404 ¢/kWh	2.567 ¢/kWh	
Penalty:	9.400 ¢/kWh	7.385 ¢/kWh	

FIXED TIME OF DELIVERY SERVICE – Primary CT Metering			
Customer Charge per Month:	\$3.00		
Monthly Minimum Bill:	Customer + Facilities Charge		
Facilities Charge per Month:	\$9.00		
	Summer	Winter	
Energy Charge per kWh:	2.393 ¢/kWh	2.556 ¢/kWh	
Penalty:	9.389 ¢/kWh	7.374 ¢/kWh	

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

Otter Tail Power Company
 Environmental Cost Recovery Rider
 North Dakota

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2018 Test Year												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
1	Revenue Requirements													
1	Air Quality Control System	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	7,090,956
2	Hoot Lake Plant MATS Project	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	490,884
3	Total Revenue Requirements	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	7,581,840
4														
5	Billed (forecast kWh x adj factor)	972,678	945,688	850,671	777,977	631,446	596,907	501,226	518,470	516,777	500,783	594,556	669,877	8,077,056
6														
7	Difference ¹	370,941	(313,868)	(218,851)	(146,157)	374	34,913	130,594	113,350	115,043	131,037	37,264	(38,057)	
8	Carrying Charge	0	2,452	394	(1,051)	(2,024)	(2,035)	(1,817)	(966)	(223)	536	1,406	1,661	(1,667)
9	Cumulative Difference (True-Up)	370,941	59,525	(158,932)	(306,140)	(307,790)	(274,912)	(146,135)	(33,751)	81,069	212,642	251,311	214,916	214,916
10														
11	Carrying Charge Calculation	2,452	394	(1,051)	(2,024)	(2,035)	(1,817)	(966)	(223)	536	1,406	1,661	1,421	(246)
12	Cumulative Carrying Charge	2,452	2,846	1,795	(229)	(2,264)	(4,081)	(5,047)	(5,270)	(4,511)	(3,105)	(1,444)	(23)	
13	Carrying cost	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	

¹ January includes estimate of \$711,799 prior period true up.

SUMMARY	2018 Test Year
Revenue requirements	\$7,581,840
Carrying Charge	(246)
Revenue requirements	<u>\$7,581,594</u>

Otter Tail Power Company
 Environmental Cost Recovery Rider
 North Dakota

		2018 Proposed ECRR Revenue Requirement and Rate												
Line No.	TRACKER SUMMARY	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected
	Requirements Compared to Billed:													
1	Revenue Requirements													
2	Air Quality Control System	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	590,913	7,090,956
3	Hoot Lake Plant MATS Project	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	40,907	490,884
4	Total Revenue Requirements	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	631,820	7,581,840
5	Billed (forecast kWh x adj factor)	972,678	945,688	850,671	777,977	631,446	596,907	501,226	518,470	516,777	500,783	594,556	669,877	8,077,056
7	Difference	(340,858)	(313,868)	(218,851)	(146,157)	374	34,913	130,594	113,350	115,043	131,037	37,264	(38,057)	
8	Carrying Charge	1,271	(1,075)	(3,157)	(4,625)	(5,621)	(5,656)	(5,463)	(4,635)	(3,917)	(3,182)	(2,337)	(2,106)	(40,503)
9	Cumulative Difference (True-Up)	(162,582)	(477,525)	(699,533)	(850,314)	(855,561)	(826,305)	(701,173)	(592,459)	(481,332)	(353,477)	(318,550)	(358,713)	(358,713)
11	Carrying Charge Calculation	(1,075)	(3,157)	(4,625)	(5,621)	(5,656)	(5,463)	(4,635)	(3,917)	(3,182)	(2,337)	(2,106)	(2,371)	(44,145)
12	Cumulative Carrying Charge	196	(2,961)	(7,585)	(13,207)	(18,863)	(24,326)	(28,961)	(32,878)	(32,143)	(34,480)	(36,586)	(38,957)	(270,750)
13	Carrying cost	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
16	Forecasted Revenue	13,068,373	11,668,720	11,120,089	9,716,025	8,834,607	9,438,727	10,319,604	10,295,655	9,995,992	10,181,735	11,535,372	12,614,663	128,789,562

SUMMARY	Jan 2018 - Dec 2018
Revenue requirements	\$7,581,840
Carrying Charge	(40,503)
December 2017 Estimated True Up	177,005
Revenue requirements	\$7,718,343
Jan 2018 - Dec 2018 projected revenue	128,789,562
January 1, 2018 Rate	5.993%

Otter Tail Power Company
 Renewable Resource Adjustment Rider
 North Dakota

Line	2018 Test Year												2018 YE Balance
	Forecast Jan-18	Forecast Feb-18	Forecast Mar-18	Forecast Apr-18	Forecast May-18	Forecast Jun-18	Forecast Jul-18	Forecast Aug-18	Forecast Sep-18	Forecast Oct-18	Forecast Nov-18	Forecast Dec-18	
1	TRACKER SUMMARY												
2	Requirements Compared to Billed:												
3	Revenue Requirements												
4	239,554	254,406	237,110	250,548	247,920	239,126	239,769	239,462	243,795	246,787	239,452	239,617	2,917,548
5	215,833	264,388	240,594	244,636	216,486	277,330	303,576	314,627	268,497	232,706	417,719	407,366	3,403,758
6	206,999	217,242	203,494	223,530	203,725	212,939	212,939	217,834	216,439	221,844	212,939	206,825	2,556,750
7	662,386	736,036	681,198	718,714	668,131	729,395	756,284	771,923	728,730	701,338	870,111	853,807	8,878,055
8													
9	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	2018 YE
10	996,022	968,384	871,087	796,647	731,408	691,401	718,812	743,542	741,114	718,177	852,658	960,676	9,789,928
11													
12	(333,636)	(230,015)	(189,076)	(78,370)	(64,233)	36,614	36,334	27,483	(13,100)	(17,643)	16,533	(107,679)	
13	352,874	122,859	(66,217)	(144,588)	(208,821)	(172,207)	(135,873)	(108,390)	(121,490)	(139,133)	(122,600)	(230,279)	
14	425,039	195,024	5,948	(72,423)	(136,656)	(100,042)	(63,708)	(36,225)	(49,325)	(66,968)	(50,435)	(158,114)	
15													
16													
17	2,333	812	(438)	(956)	(1,381)	(1,138)	(898)	(717)	(803)	(920)	(811)	(1,522)	(6,438.19)
18	788,680	789,492	789,054	788,098	786,718	785,579	784,681	783,965	783,161	782,242	781,431	779,909	
19	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	
20	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	
21													
22	355,207	123,671	(66,655)	(145,544)	(210,201)	(173,346)	(136,772)	(109,107)	(122,294)	(140,053)	(123,410)	(231,801)	
23													
24	13,068,373	11,668,720	11,120,089	9,716,025	8,834,607	9,438,727	10,319,604	10,295,655	9,995,992	10,181,735	11,535,372	12,614,663	128,789,562

¹ January includes estimate of \$686,510 prior period true-up.

2018 Test Year	
Revenue Requirements	8,878,055
Carrying Charge	(6,438)
Total Requirements	8,871,617

Otter Tail Power Company
 Renewable Resource Adjustment Rider
 North Dakota

2018 Proposed RRAR Revenue Requirement and Rate

Line	Forecast Jan-18	Forecast Feb-18	Forecast Mar-18	Forecast Apr-18	Forecast May-18	Forecast Jun-18	Forecast Jul-18	Forecast Aug-18	Forecast Sep-18	Forecast Oct-18	Forecast Nov-18	Forecast Dec-18	2018 YE Balance
1	TRACKER SUMMARY												
2	Requirements Compared to Billed:												
3	Revenue Requirements												
4	239,554	254,406	237,110	250,548	247,920	239,126	239,769	239,462	243,795	246,787	239,452	239,617	2,917,548
5	215,833	264,388	240,594	244,636	216,486	277,330	303,576	314,627	268,497	232,706	417,719	407,366	3,403,758
6	206,999	217,242	203,494	223,530	203,725	212,939	212,939	217,834	216,439	221,844	212,939	206,825	2,556,750
7	662,386	736,036	681,198	718,714	668,131	729,395	756,284	771,923	728,730	701,338	870,111	853,807	8,878,055
8													
9	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	2018 YE
10	979,159	874,288	833,182	727,981	661,940	707,204	773,205	771,410	748,958	762,875	864,297	945,164	9,649,664
11													
12	(311,451)	(135,334)	(149,960)	(8,235)	7,168	23,216	(15,742)	1,587	(19,143)	(60,579)	6,372	(90,757)	
13	441,406	306,072	156,112	147,877	155,045	178,261	162,519	164,106	144,964	84,385	90,757	(0.00)	
14	447,224	311,890	161,930	153,695	160,864	184,079	168,337	169,925	150,782	90,203	96,575	5,818.17	
15													
16													
17	2,918	2,023	1,032	978	1,025	1,178	1,074	1,085	958	558	600	(0.00)	
18	789,265	791,288	792,320	793,298	794,323	795,502	796,576	797,661	798,619	799,177	799,777	799,777.09	
19	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	
20	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	0.66110%	
21													
22	444,324	308,096	157,144	148,855	156,070	179,439	163,593	165,191	145,922	84,943	91,357	(0)	(0.00)
23													
24	13,068,373	11,668,720	11,120,089	9,716,025	8,834,607	9,438,727	10,319,604	10,295,655	9,995,992	10,181,735	11,535,372	12,614,663	128,789,562

Rate Calculation - Calendar Year 2018	
Revenue Requirements Jan 2018 thru Dec 2018	8,878,055
Carrying Charge	13,430
Cumulative True-up	758,179
Total Requirements	9,649,664
Jan 2018 - Dec 2018 projected revenue	128,789,562
January 1, 2018 Rate	7.493%

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2018 Test Year												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
1	Revenue Requirements													
1	CAPX 2020: Fargo	205,171	205,171	207,001	205,171	205,171	207,001	205,171	205,171	207,001	205,171	205,171	207,001	2,469,369
2	CAPX 2020: Bemidji	50,556	50,556	50,556	50,556	50,556	50,556	50,556	50,556	50,556	50,556	50,556	50,556	606,672
3	Cass Lake-Nary-Helga-Bemidji	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	98,404
4	Rugby Wind Interconnection	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,486
5	Casselton – Buffalo 115 kV Project	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	253,204
6	CAPX 2020: Brookings - Hampton	18,346	18,346	18,500	18,346	18,346	18,500	18,346	18,346	18,500	18,346	18,346	18,500	220,764
7	MVP: Big Stone Area Transmission	5,245	5,249	5,253	5,257	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	63,053
8	MVP: Ellendale to Big Stone South	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	74,419
9	Ramsey 230/115 kW Transformer Upgrade	1,174	1,174	1,174	1,174	1,174	1,174	1,174	1,174	1,174	1,174	1,174	1,174	14,090
10	Karlstad, MN Capacitor Bank Project	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	36,455
11	Oakes Area Transmission Improvements	17,629	17,629	17,629	17,629	17,629	17,629	17,629	17,629	17,629	17,629	17,629	17,629	211,544
12	Hankinson Transformer Addition	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	23,998
13	NERC Compliance	42,304	42,304	42,304	42,304	42,304	42,304	42,304	42,304	42,304	42,304	42,304	42,304	507,654
14	Summit Transformer	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	25,652
15	Spiritwood Station Interconnection	2,014	2,014	2,014	2,014	2,014	2,014	2,014	2,014	2,014	2,014	2,014	2,014	24,169
16	Max- Ryder 41.6 kV Line Upgrades	2,097	2,097	2,097	2,097	2,097	2,097	2,097	2,097	2,097	2,097	2,097	2,097	25,889
17	Rugby Breaker Station	3,941	3,941	3,941	3,941	3,941	3,941	3,941	3,941	3,941	3,941	3,941	3,941	47,292
18	Granville Jct Breaker Station	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	25,932
19	Bagley 115kV Switch Station	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	5,353	5,353	52,776
20	Total Revenue Requirements	398,564	398,567	400,555	398,575	398,575	400,559	398,575	398,575	400,559	398,575	399,721	402,427	4,793,824
21														
22	MISO & SPP Expenses													
23	MISO Schedule 26 Expense	485,727	445,667	425,637	365,547	315,472	345,517	400,600	400,600	345,517	390,585	400,600	500,749	4,822,217
24	MISO Schedule 26A Expense	289,914	261,250	252,884	221,319	205,456	202,418	220,116	220,191	210,355	221,643	247,196	276,620	2,829,362
25	SPP Schedule 9 Expense	4,654	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	852,795
26	SPP Schedule 11 Expense	3,292	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	74,798
27	Total MISO & SPP Expenses	783,587	790,521	762,125	670,470	604,532	631,539	704,320	704,395	639,476	695,832	731,399	860,974	8,579,172
28														
29	MISO Revenues													
30	MISO Schedule 9 Revenue	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(30,910)	(370,917)
31	MISO Schedule 26 Revenue	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(408,997)	(4,907,968)
32	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
33	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
34	MISO Schedule 26A Revenue	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(54,130)	(649,555)
35	MISO MVP ARR Revenue	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(2,178)	(26,135)
36	Total MISO Revenues	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(496,215)	(5,954,575)
37														
38	Net Revenue Requirement	685,936	692,874	666,466	572,832	506,892	535,884	606,680	606,756	543,821	598,192	634,906	767,187	7,418,426
39														
40	Billed (forecast kWh x adj factor)	777,027	755,466	679,562	621,489	504,433	476,841	495,746	512,802	511,127	495,308	588,056	662,553	7,080,410
41														
42	Difference	(91,091)	(62,592)	(13,096)	(48,657)	2,459	59,043	110,934	93,954	32,694	102,884	46,850	104,634	338,016
43	Carrying Charge	0	(2,659)	(3,090)	(3,197)	(3,540)	(3,547)	(3,181)	(2,468)	(1,863)	(1,660)	(990)	(687)	(26,884)
44	Cumulative Difference ¹	(402,223)	(467,474)	(483,661)	(535,515)	(536,596)	(481,101)	(373,348)	(281,862)	(251,031)	(149,806)	(103,947)	0	0
45														
46	Carrying Charge Calculation	(2,659)	(3,090)	(3,197)	(3,540)	(3,547)	(3,181)	(2,468)	(1,863)	(1,660)	(990)	(687)	0	
47	Cumulative Carrying Charge	(2,659)	(5,750)	(8,947)	(12,487)	(16,035)	(19,215)	(21,683)	(23,547)	(25,206)	(26,197)	(26,884)	(26,884)	
48	Carrying cost	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	
49														
50														
51														
52														

¹ January includes estimate of \$311,132 prior period true-up.

SUMMARY		2018 Test Year
Revenue requirements		\$7,418,426
Carrying Charge		(26,884)
Total requirements		\$7,391,542

Class Allocation and Rate Design

Line No.			2018
1	North Dakota Revenue Requirements		\$7,469,920 *
2	Large General Service Class	27.77%	\$2,074,098
3	Controlled Service	2.77%	206,997
4	Lighting	0.96%	71,724
5	All Other Service	68.50%	5,117,101
6	Total		\$7,469,920
7	Large General Service Class	kW	1,270,619
8	Controlled Service	kWh	243,255,777
9	Lighting	kWh	23,001,296
10	All Other Service	kWh	942,842,036
11	Large General Service Class	\$ / kW	1.632
12	Controlled Service	cents / kWh	0.085
13	Lighting	cents / kWh	0.312
14	All Other Service	cents / kWh	0.543

* Jurisdictional transmission allocation factor (D2 = 39.598907%) is from Otter Tail's proposed general rate case in North Dakota Case No. PU-17-398.

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2018												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
1	Revenue Requirements													
2	CAPX 2020: Fargo	203,090	203,090	204,920	203,090	203,090	204,920	203,090	203,090	204,920	203,090	203,090	204,920	2,444,397
3	CAPX 2020: Bemidji	49,445	49,445	53,060	49,445	49,445	53,060	49,445	49,445	53,060	49,445	49,445	53,060	607,803
4	Cass Lake-Nary-Helga-Bemidji	8,149	8,149	8,149	8,077	8,077	8,077	8,077	8,077	8,077	8,077	8,077	8,077	97,140
5	Rugby Wind Interconnection	171	171	171	171	171	171	171	171	171	171	171	171	2,058
6	Casselton - Buffalo 115 kV Project	23,117	23,117	23,117	23,117	23,117	23,117	23,117	23,117	23,117	23,117	23,117	23,117	277,399
7	CAPX 2020: Brookings - Hampton	18,365	18,365	18,519	18,365	18,365	18,519	18,365	18,365	18,365	18,519	18,365	18,519	220,994
8	MVP: Big Stone Area Transmission	5,195	5,198	5,202	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	62,455
9	MVP: Ellendale to Big Stone South	6,805	6,805	6,805	6,805	6,805	6,805	6,805	6,805	6,805	6,805	6,805	6,805	81,660
10	Ramsey 230/115 kW Transformer Upgrade	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082	12,988
11	Karlstad, MN Capacitor Bank Project	3,234	3,234	3,234	3,234	3,234	3,234	3,234	3,234	3,234	3,234	3,234	3,234	38,803
12	Oakes Area Transmission Improvements	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	224,925
13	Hankinson Transformer Addition	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	2,161	25,931
14	NERC Compliance	41,634	41,634	41,634	41,634	41,634	41,634	41,634	41,634	41,634	41,634	41,634	41,634	499,612
15	Summit Transformer	2,109	2,109	2,109	2,109	2,109	2,109	2,109	2,109	2,109	2,109	2,109	2,109	25,303
16	Spiritwood Station Interconnection	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	27,035
17	Max- Ryder 41.6 kV Line Upgrades	5,070	5,101	5,131	5,162	5,192	5,223	5,253	5,284	5,314	5,344	5,375	5,405	62,854
18	Rugby Breaker Station	4,833	4,833	4,833	4,833	4,833	4,833	4,833	4,833	4,833	4,833	4,833	4,833	58,002
19	Granville Jct Breaker Station	2,676	2,676	2,676	2,676	2,676	2,676	2,676	2,676	2,676	2,676	2,676	2,676	32,117
20	Bagley 115kV Switch Station	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	59,359
21	Total Revenue Requirements	402,889	402,923	408,557	402,920	402,950	408,580	403,011	403,042	408,672	403,103	404,278	409,908	4,860,834
22	MISO & SPP Expenses													
23	MISO Schedule 26 Expense	485,728	445,668	425,638	365,548	315,473	345,518	400,600	400,600	345,518	390,585	400,600	500,750	4,822,225
24	MISO Schedule 26A Expense	289,914	261,250	252,884	221,319	205,456	202,418	220,116	220,192	210,355	221,644	247,196	276,621	2,829,366
25	SPP Schedule 9 Expense	4,654	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	77,104	852,796
26	SPP Schedule 11 Expense	3,292	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	74,798
27	Total MISO & SPP Expenses	783,588	790,522	762,126	670,471	604,533	631,540	704,321	704,396	639,477	695,833	731,401	860,975	8,579,185
28	MISO Revenues													
29	MISO Schedule 9 Revenue	(37,079)	(17,751)	(24,582)	(37,019)	(4,647)	(21,663)	(27,784)	(31,121)	(23,499)	(39,206)	(44,465)	(66,520)	(375,335)
30	MISO Schedule 26 Revenue	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(413,643)	(4,963,718)
31	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
32	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
33	MISO Schedule 26A Revenue	(50,997)	(50,984)	(50,992)	(50,986)	(50,996)	(50,997)	(51,011)	(51,013)	(51,028)	(51,036)	(51,039)	(51,040)	(612,118)
34	MISO MVP ARR Revenue	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(1,782)	(21,383)
35	Total MISO Revenues	(503,500)	(484,160)	(490,999)	(503,430)	(471,068)	(488,085)	(494,220)	(497,559)	(489,952)	(505,667)	(510,929)	(532,985)	(5,972,554)
36	Net Revenue Requirement	682,977	709,285	679,684	569,962	536,415	552,036	613,113	609,879	558,197	593,269	624,750	737,899	7,467,464
37														
38	Billed (forecast kWh x adj factor)	819,773	797,026	716,946	655,679	532,183	503,073	523,018	541,012	539,245	522,556	620,406	699,002	7,469,920
39														
40	Difference	(136,797)	(87,742)	(37,262)	(85,717)	4,232	48,963	90,095	68,867	18,951	70,713	4,344	38,897	(2,456)
41	Carrying Charge	122	(859)	(1,495)	(1,773)	(2,401)	(2,388)	(2,054)	(1,422)	(938)	(808)	(306)	(277)	(14,599)
42	Cummulative Difference	(119,619)	(208,219)	(246,976)	(334,467)	(332,636)	(286,062)	(198,021)	(130,576)	(112,562)	(42,657)	(38,619)	(0)	(0)
43														
44	Carrying Charge Calculation	(859)	(1,495)	(1,773)	(2,401)	(2,388)	(2,054)	(1,422)	(938)	(808)	(306)	(277)	(0)	
45	Cumulative Carrying Charge	(110,514)	(112,009)	(113,782)	(116,183)	(118,572)	(120,626)	(122,047)	(122,985)	(123,793)	(124,099)	(124,377)	(124,377)	
46	Carrying cost	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	
47														
48	Forecasted Sales (MWh)	198,821	193,304	173,882	159,023	129,071	122,011	126,848	131,213	130,784	126,736	150,468	169,530	1,811,694
49														
50														
51														
52														

	Jan 2018 - Dec 2018
SUMMARY	
Revenue requirements	\$7,467,464
Carrying Charge	(14,599)
2017 True-Up	17,055
Total requirements	\$7,469,920

LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	RATE BASE		Page 2-1 Line 32	776,594,536	223,306,067	553,288,470	1
2							2
3	TOTAL AVAILABLE FOR RETURN		Page 7-1 Line 43	80,145,944	11,486,268	68,659,675	3
4							4
5	RATE OF RETURN EARNED			10.32%	5.14%	12.41%	5
6							6
7	RATE OF RETURN REQUESTED		Page 17-1 Line 11		7.96%		7
8							8
9	OPERATING INCOME REQUIRED				17,775,163		9
10							10
11	TOTAL AVAILABLE FOR RETURN				11,486,268		11
12							12
13	OPERATING INCOME DEFECIENCY				6,288,895		13
14							14
15	INCREMENTAL TAXES	GRCF = 1.322837			2,030,288		15
16							16
17	REVENUE INCREASE REQUIRED				8,319,183		17
18							18
19	PERCENTAGE INCREASE				6.79%		19
20							20
21							21
22							22
23							23
24							24
25	RETURN ON EQUITY				4.93%		25
26							26
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LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ELECTRIC PLANT IN SERVICE		Page 3-1 Line 52	1,422,111,765	529,263,615	892,848,150	1
2							2
3	ACCUMULATED DEPRECIATION		Page 4-12 Line 22	(639,479,296)	(256,695,448)	(382,783,847)	3
4				782,632,470	272,568,167	510,064,303	4
5	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS						5
6							6
7	NET CAPITALIZED ITEMS - BIG STONE PLANT		Page 4-1 Line 28	0	0	0	7
8							8
9	NET ELECTRIC PLANT IN SERVICE			782,632,470	272,568,167	510,064,303	9
10							10
11	PLANT HELD FOR FUTURE USE		Page 4-1 Line 47	29,657	13,044	16,613	11
12							12
13	CONSTRUCTION WORK IN PROGRESS		Page 5-1 Line 31	125,054,506	271,748	124,782,759	13
14							14
15	MATERIALS AND SUPPLIES		Page 5-1 Line 39	19,265,037	7,946,645	11,318,392	15
16							16
17	FUEL STOCKS		Page 5-1 Line 46	12,099,676	4,430,805	7,668,871	17
18							18
19	PREPAYMENTS		Page 5-1 Line 49	(36,579,505)	(12,739,580)	(23,839,925)	19
20							20
21	CUSTOMER ADVANCES		Page 5-1 Line 51	(1,013,988)	(353,143)	(660,846)	21
22							22
23	CASH WORKING CAPITAL		Page 5-1 Line 53	13,522,643	3,548,095	9,974,548	23
24							24
25	ACCUMULATED DEFERRED INCOME TAXES		Page 6-1 Line 16	(138,415,960)	(52,379,715)	(86,036,245)	25
26							26
27	UNAMORTIZED BALANCE - SPIRITWOOD		Page 6-1 Line 19	0	0	0	27
28							28
29	UNAMORTIZED RATE CASE EXPENSE		Page 6-1 Line 22	0	0	0	29
30							30
31							31
32	TOTAL AVERAGE RATE BASE			776,594,536	223,306,067	553,288,470	32
33							33
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LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	PLANT IN SERVICE						1
2	A/C 101 & 106 - Direct MN	Direct MN		3,520,019	0	3,520,019	2
3	A/C 101 & 106 - Direct ND	Direct ND		471,573	471,573	0	3
4	A/C 101 & 106 - Direct SD	Direct SD		1,146,073	0	1,146,073	4
5	Subtotal A/C 101 & 106 - Direct Assigned			5,137,665	471,573	4,666,092	5
6							6
7	PRODUCTION PLANT						7
8	A/C 101 & 106 - BASE DEMAND	E1		376,022,810	134,083,371	241,939,440	8
9	PEAK DEMAND	D1		47,798,244	19,043,037	28,755,207	9
10	BASE ENERGY	E2		32,751	12,307	20,444	10
11							11
12	SUBTOTAL A/C 101 & 106			428,991,470	153,610,287	275,381,183	12
13							13
14	A/C 114 - BASE DEMAND	E1		1,298,081	462,874	835,207	14
15	PEAK DEMAND	D1		290,174	115,607	174,567	15
16	BASE ENERGY	E1		0	0	0	16
17							17
18	SUBTOTAL A/C 114			1,588,255	578,480	1,009,774	18
19							19
20	TOTAL PRODUCTION PLANT	P10	310-317, 330-335, 340-347	430,579,725	154,188,767	276,390,957	20
21							21
22	TRANSMISSION PLANT						22
23							23
24	A/C 101 & 106	D2		264,273,051	104,649,241	159,623,810	24
25	A/C 101 & 106 (Direct FERC)	Direct FERC		126,520,627	0	126,520,627	25
26	A/C 114	D2		58,287	23,061	35,206	26
27							27
28	TOTAL TRANSMISSION PLANT		350-350.1, 353-356, 358	390,851,965	104,672,322	286,179,643	28
29							29
30							30
31	DISTRIBUTION PLANT						31
32	PRIMARY DEMAND	D3	360, 362, 364-365, 367	186,296,581	85,455,191	100,841,391	32
33	SECONDARY DEMAND	D4	365, 367-369.1	102,024,443	48,993,034	53,031,409	33
34	PRIMARY CUSTOMER	C2	364-365, 367	78,110,166	34,970,609	43,139,556	34
35	SECONDARY CUSTOMER	C3	365, 367-369.1, 370.2	74,280,016	33,265,375	41,014,641	35
36	STREETLIGHTING	C4	364-365, 367, 373	13,953,157	6,080,955	7,872,203	36
37	AREA LIGHTING	C5	364-365, 367, 371.2	8,020,685	4,151,739	3,868,946	37
38	METERS	C6	370	26,594,087	11,882,166	14,711,920	38
39	LOAD MANAGEMENT	C9	370.1	8,713,737	3,794,879	4,918,858	39
40							40
41	TOTAL DISTRIBUTION PLANT	P60		497,992,871	228,593,947	269,398,924	41
42							42
43							43
44	GENERAL PLANT						44
45	PRODUCTION	P10		33,883,326	12,061,856	21,821,470	45
46	TRANSMISSION	D2		13,030,498	5,159,935	7,870,563	46
47	DISTRIBUTION	P60		21,099,100	9,685,132	11,413,968	47
48	CUSTOMER ACCOUNTS	OXC		16,779,859	7,380,245	9,399,614	48
49	CUSTOMER SERVICE & INFO	OXI		3,709,137	1,655,501	2,053,636	49
50	LOAD MANAGEMENT	C9	397.3	317,859	138,429	179,429	50
51							51
52	TOTAL GENERAL PLANT	P90	389-398, 390.1-390.3, 391.1-391.6, 394.2, 397.1-397.2	88,619,779	36,081,097	52,538,682	52
53							53
54							54
55	INTANGIBLE PLANT	P90	302-303	14,067,426	5,727,482	8,339,944	55
56							56
57							57
58	TOTAL PLANT IN SERVICE	EPIS		1,422,111,765	529,263,615	892,848,150	58
59							59
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63							63
64							64
65							65
66							66

LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEPRECIATION						1
2	PRODUCTION PLANT						2
3	BASE DEMAND	E1	108, 115	(223,576,017)	(79,723,424)	(143,852,593)	3
4	PEAK DEMAND	D1	108, 115	(46,728,160)	(18,616,711)	(28,111,450)	4
5	BASE ENERGY	E2	108	15,504	5,826	9,678	5
6							6
7	TOTAL PRODUCTION PLANT			(270,288,673)	(98,334,308)	(171,954,365)	7
8							8
9							9
10	TRANSMISSION PLANT	D2	108, 115	(114,281,523)	(45,254,235)	(69,027,289)	10
11	TRANSMISSION PLANT (Direct FERC)	Direct FERC		(4,418,753)	0	(4,418,753)	11
12	TOTAL TRANSMISSION PLANT			(118,700,277)	(45,254,235)	(73,446,042)	12
13							13
14							14
15	DISTRIBUTION PLANT	P60	108, 115	(214,337,362)	(98,387,400)	(115,949,962)	15
16							16
17							17
18	GENERAL PLANT	P90	108	(34,142,419)	(13,900,914)	(20,241,505)	18
19							19
20							20
21	INTANGIBLE PLANT	P90	108	(2,010,565)	(818,591)	(1,191,973)	21
22							22
23							23
24	TOTAL ACCUMULATED DEPRECIATION			(639,479,296)	(256,695,448)	(382,783,847)	24
25							25
26							26
27	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS			782,632,470	272,568,167	510,064,303	27
28							28
29							29
30	BSP CAPITALIZED ITEMS	P10		0	0	0	30
31							31
32	TOTAL NET PLANT IN SERVICE	NEPIS		782,632,470	272,568,167	510,064,303	32
33							33
34							34
35							35
36							36
37							37
38							38
39							39
40							40
41							41
42	PLANT HELD FOR FUTURE USE						42
43	PRODUCTION PLANT	P10		0	0	0	43
44	TRANSMISSION PLANT	D2		9,038	3,579	5,459	44
45	DISTRIBUTION PLANT	P60		20,619	9,465	11,154	45
46	GENERAL PLANT	P90		0	0	0	46
47	INTANGIBLE PLANT	P90		0	0	0	47
48							48
49	TOTAL PLANT HELD FOR FUTURE USE		105	29,657	13,044	16,613	49
50							50
51							51
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LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	<u>CONST WORK-IN-PROGRESS - Direct Assigned</u>						1
2	PRODUCTION PLANT - Direct MN	P10	Directly Assigned to Jurisdiction	0	0	0	2
3	PRODUCTION PLANT - Direct ND	P10	Directly Assigned to Jurisdiction	0	0	0	3
4	PRODUCTION PLANT - Direct SD	P10	Directly Assigned to Jurisdiction	0	0	0	4
5	PRODUCTION PLANT - Direct FERC	Direct FERC	Directly Assigned to FERC	0	0	0	5
6	TRANSMISSION PLANT - Direct MN	D2	Directly Assigned to Jurisdiction	0	0	0	6
7	TRANSMISSION PLANT - Direct ND	D2	Directly Assigned to Jurisdiction	0	0	0	7
8	TRANSMISSION PLANT - Direct SD	D2	Directly Assigned to Jurisdiction	0	0	0	8
9	TRANSMISSION PLANT - Direct FERC	Direct FERC	Directly Assigned to FERC	95,776,331	0	95,776,331	9
10	DISTRIBUTION PLANT - Direct MN	P60	Directly Assigned to Jurisdiction	0	0	0	10
11	DISTRIBUTION PLANT - Direct ND	P60	Directly Assigned to Jurisdiction	0	0	0	11
12	DISTRIBUTION PLANT - Direct SD	P60	Directly Assigned to Jurisdiction	0	0	0	12
13	DISTRIBUTION PLANT - Direct FERC	Direct FERC	Directly Assigned to FERC	0	0	0	13
14	GENERAL PLANT - Direct MN	P90	Directly Assigned to Jurisdiction	0	0	0	14
15	GENERAL PLANT - Direct ND	P90	Directly Assigned to Jurisdiction	0	0	0	15
16	GENERAL PLANT - Direct SD	P90	Directly Assigned to Jurisdiction	0	0	0	16
17	GENERAL PLANT - Direct FERC	Direct FERC	Directly Assigned to FERC	0	0	0	17
18	INTANGIBLE PLANT - Direct MN	P90	Directly Assigned to Jurisdiction	0	0	0	18
19	INTANGIBLE PLANT - Direct ND	P90	Directly Assigned to Jurisdiction	0	0	0	19
20	INTANGIBLE PLANT - Direct SD	P90	Directly Assigned to Jurisdiction	0	0	0	20
21	INTANGIBLE PLANT - Direct FERC	Direct FERC	Directly Assigned to FERC	0	0	0	21
22	TOTAL CWIP - Direct Assigned		ALLOWED ONLY IN MN & FERC	95,776,331	0	95,776,331	22
23							23
24							24
25	<u>CONST WORK-IN-PROGRESS - SHORT-TERM</u>						25
26	PRODUCTION PLANT	P10		0	0	0	26
27	TRANSMISSION PLANT	D2		686,250	271,748	414,502	27
28	DISTRIBUTION PLANT	P60		0	0	0	28
29	GENERAL PLANT	P90		0	0	0	29
30	INTANGIBLE PLANT	P90		0	0	0	30
31							31
32	TOTAL CWIP - SHORT-TERM		ALLOWED ONLY IN MN, ND & FERC	686,250	271,748	414,502	32
33							33
34							34
35	<u>CONST WORK-IN-PROGRESS - LONG TERM</u>						35
36	PRODUCTION PLANT (AFUDC Projects)	P10		14,041,071	0	14,041,071	36
37	PRODUCTION PLANT (Rider Projects)	P10		0	0	0	37
38	TRANSMISSION PLANT (AFUDC Projects)	D2		5,855,294	0	5,855,294	38
39	TRANSMISSION PLANT (Rider Projects)	D2		0	0	0	39
40	DISTRIBUTION PLANT	P60		1,149,148	0	1,149,148	40
41	GENERAL PLANT	P90		1,603,969	0	1,603,969	41
42	INTANGIBLE PLANT	P90		5,942,443	0	5,942,443	42
43							43
44	TOTAL CWIP - LONG TERM - AFUDC Projects		ALLOWED ONLY IN MN & FERC	28,591,925	0	28,591,925	44
45	TOTAL CWIP - LONG TERM - Rider Projects			0	0	0	45
46							46
47							47
48	TOTAL CONSTRUCTION WORK-IN-PROGRESS		107	125,054,506	271,748	124,782,759	48
49							49
50							50
51	<u>MATERIALS & SUPPLIES</u>						51
52	PRODUCTION	P10		5,478,732	1,961,911	3,516,822	52
53	TRANSMISSION	D2		5,450,400	2,158,299	3,292,101	53
54	DISTRIBUTION	P60		8,335,905	3,826,435	4,509,470	54
55							55
56	TOTAL MATERIALS AND SUPPLIES		154, 158.1	19,265,037	7,946,645	11,318,392	56
57							57
58							58
59	<u>FUEL STOCKS</u>						59
60	COAL STOCKS	E1		9,319,627	3,323,221	5,996,406	60
61	FUEL OIL STOCKS	D1		2,780,049	1,107,584	1,672,465	61
62							62
63	TOTAL FUEL STOCKS		1510	12,099,676	4,430,805	7,668,871	63
64							64
65							65
66	PREPAYMENTS	NEPIS	128, 228.3	(36,579,505)	(12,739,580)	(23,839,925)	66
67							67
68	CUSTOMER ADVANCES	NEPIS	235, 253	(1,013,988)	(353,143)	(660,846)	68
69							69
70	CASH WORKING CAPITAL	OX		13,522,643	3,548,095	9,974,548	70
71							71
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LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEFERRED INCOME TAXES						1
2	ITEMS SD FLOWS THROUGH						2
3	FEDERAL	NPMNR		435,531	164,922	270,609	3
4	MINNESOTA	NPISM		72,069	0	72,069	4
5	NORTH DAKOTA	NPISN		35,772	35,772	0	5
6							6
7	SUBTOTAL			543,371	200,693	342,678	7
8							8
9	ALL OTHER						9
10	FEDERAL	NEPIS		(45,449,430)	(15,828,717)	(29,620,713)	10
11	FEDERAL (Direct FERC)	Direct FERC		(23,579,516)	0	(23,579,516)	11
12	MINNESOTA	NPISM		(33,178,694)	0	(33,178,694)	12
13	NORTH DAKOTA	NPISN		(36,751,691)	(36,751,691)	0	13
14							14
15	SUBTOTAL			(138,959,331)	(52,580,408)	(86,378,923)	15
16							16
17	TOTAL ACCUMULATED DEFERRED INCOME TAXES		190,255,281-283	(138,415,960)	(52,379,715)	(86,036,245)	17
18							18
19							19
20	UNAMORTIZED BALANCE - SPIRITWOOD PLAN	P10		0	0	0	20
21							21
22							22
23	UNAMORTIZED RATE CASE EXPENSES	R10		0	0	0	23
24							24
25							25
26							26
27							27
28	TOTAL AVERAGE RATE BASE			776,594,536	223,306,067	553,288,470	28
29							29
30							30
31							31
32							32
33							33
34							34
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING REVENUES					1
2	SALES OF ELECTRICITY		369,865,140	122,589,268	237,275,872	2
3	OTHER OPERATING REVENUE		58,232,545	9,712,037	48,520,508	3
4						4
5	TOTAL OPERATING REVENUE		418,097,684	132,301,305	285,796,380	5
6						6
7						7
8	OPERATING EXPENSES					8
9	PRODUCTION EXPENSES		157,419,523	58,417,943	99,001,580	9
10	TRANSMISSION EXPENSES		29,047,280	11,026,754	18,020,526	10
11	DISTRIBUTION EXPENSES		16,917,384	7,680,921	9,236,463	11
12	CUSTOMER ACCOUNTING EXPENSES		13,849,926	6,091,579	7,758,346	12
13	CUSTOMER SERVICE AND INFORMATION EXPENSES		11,097,740	1,382,509	9,715,231	13
14	SALES EXPENSES		273,627	22,472	251,155	14
15	ADMINISTRATIVE AND GENERAL EXPENSES		49,279,686	19,282,795	29,996,891	15
16	CHARITABLE CONTRIBUTIONS		0	0	0	16
17	DEPRECIATION EXPENSE		35,016,724	13,387,642	21,629,082	17
18	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	18
19	SPIRITWOOD AMORTIZATION		0	0	0	19
20	GENERAL TAXES		13,082,883	3,936,734	9,146,149	20
21						21
22	TOTAL OPERATING EXPENSES		325,984,772	121,229,349	204,755,423	22
23						23
24						24
25	NET OPERATING INCOME BEFORE INCOME TAXES		92,112,912	11,071,955	81,040,957	25
26						26
27						27
28	INCOME TAX EXPENSE					28
29	INVESTMENT TAX CREDIT		(3,180,509)	(1,183,682)	(1,996,827)	29
30	DEFERRED INCOME TAXES		(5,866,242)	(1,639,469)	(4,226,773)	30
31	INCOME TAXES		23,041,293	2,408,838	20,632,455	31
32						32
33	TOTAL INCOME TAX EXPENSE		13,994,542	(414,313)	14,408,855	33
34						34
35						35
36						36
37	NET OPERATING INCOME		78,118,369	11,486,268	66,632,101	37
38						38
39						39
40	Allowance for Funds Used During Construction		2,027,574	0	2,027,574	40
41	Allowance for Funds Used During Construction - MN Only		0	0	0	41
42	Allowance for Funds Used During Construction - SD Only		0	0	0	42
43	TOTAL ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION		2,027,574	0	2,027,574	43
44						44
45						45
46	TOTAL AVAILABLE FOR RETURN		80,145,944	11,486,268	68,659,675	46
47						47
48						48
49						49
50						50
51	AVERAGE CENTS PER KWH					51
52						52
53						53
54						54
55						55
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60						60
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63						63

LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING EXPENSES						1
2	PRODUCTION EXPENSES						2
3	PROD EXPENSES EXCLUDING PURCHASED POWER						3
4	BASE DEMAND	E1	500, 502, 505-507, 509-511, 535, 537-543, 546, 548-554, 556-557	15,816,424	5,639,869	10,176,555	4
5	PEAK DEMAND	D1	500, 502, 506-507, 509-511, 535, 537-543, 546, 548-554, 556-557	3,422,425	1,363,510	2,058,916	5
6	BASE ENERGY	E2	501, 512-514, 544-546, 548-554	66,148,362	24,856,796	41,291,566	6
7	PEAK ENERGY	D1	547	508,600	202,629	305,971	7
8	BASE DEMAND (Direct MN)			1,032,569	0	1,032,569	8
9	PEAK DEMAND (Direct MN)			230,821	0	230,821	9
10							10
11	TOTAL EXCLUDING PURCHASED POWER			87,159,201	32,062,803	55,096,397	11
12					0		12
13					0		13
14	PURCHASED POWER				0		14
15	BUY SELL TRANSACTIONS	D2		0		0	15
16	ALL OTHER TRANSACTIONS				0		16
17	BASE DEMAND	E1	555	2,439,877	870,019	1,569,858	17
18	PEAK DEMAND	D1		0	0	0	18
19	BASE ENERGY	E2	555	67,820,445	25,485,120	42,335,325	19
20	PEAK ENERGY	D1		0	0	0	20
21							21
22	TOTAL ALL OTHER TRANSACTIONS			70,260,322	26,355,139	43,905,183	22
23							23
24	TOTAL PURCHASED POWER			70,260,322	26,355,139	43,905,183	24
25							25
26	TOTAL PRODUCTION EXPENSES			157,419,523	58,417,943	99,001,580	26
27							27
28							28
29	TRANSMISSION EXPENSES	D2	560, 561.1-561.2, 561.4-561.6, 562-563, 565-568, 569.1-569.3, 570-573	27,846,108	11,026,754	16,819,353	29
30	TRANSMISSION EXPENSES (Direct MN)			1,184,949	0	1,184,949	30
31	TRANSMISSION EXPENSES (Direct FERC)	Direct FERC		16,223	0	16,223	31
32	TOTAL TRANSMISSION EXPENSES			29,047,280	11,026,754	18,020,526	32
33							33
34							34
35	DISTRIBUTION EXPENSES						35
36	PRIMARY DEMAND	D3	580-584, 588-590, 592-594, 598	5,246,930	2,406,793	2,840,136	36
37	SECONDARY DEMAND	D4	580-581, 583-584, 588, 590, 593-595, 598	1,880,361	902,966	977,395	37
38	PRIMARY CUSTOMER	C2	580-581, 583-584, 588-590, 593-594, 598	3,090,357	1,383,580	1,706,777	38
39	SECONDARY CUSTOMER	C3	580-581, 583-584, 587-588, 590, 593-595, 598	2,200,175	985,321	1,214,854	39
40	STREETLIGHTING	C4	580-581, 583-585, 588-590, 593-594, 596, 598	1,662,551	724,560	937,991	40
41	AREA LIGHTING	C5	580-581, 583-584, 588-590, 593-594, 598	143,049	74,046	69,003	41
42	METERS	C6	580-581, 586, 588, 597-598	2,893,960	1,203,654	1,490,306	42
43	LOAD MANAGEMENT	C9		0	0	0	43
44							44
45	TOTAL DISTRIBUTION	OXD		16,917,384	7,680,921	9,236,463	45
46							46
47							47
48	CUSTOMER ACCOUNTING EXPENSES						48
49	METER READING	C7	901-902	5,356,450	2,289,472	3,066,978	49
50	OTHER	C8	901, 903-905	8,493,476	3,802,108	4,691,368	50
51							51
52	TOTAL CUSTOMER ACCOUNTS	OXC		13,849,926	6,091,579	7,758,346	52
53							53
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LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEPRECIATION EXPENSE						1
2	<u>PRODUCTION</u>						2
3	BASE DEMAND	E1		10,181,475	3,630,542	6,550,933	3
4	PEAK DEMAND	D1		1,108,806	441,753	667,052	4
5	BASE ENERGY	E2		0	0	0	5
6							6
7	TOTAL PRODUCTION			11,290,280	4,072,295	7,217,986	7
8							8
9							9
10	TRANSMISSION	D2		5,102,072	2,020,365	3,081,707	10
11	TRANSMISSION (Direct FERC)	Direct FERC		2,202,087	0	2,202,087	11
12	TOTAL TRANSMISSION			7,304,159	2,020,365	5,283,794	12
13							13
14							14
15	DISTRIBUTION	P60		11,732,197	5,385,437	6,346,760	15
16							16
17							17
18	GENERAL	P90		2,285,866	930,679	1,355,187	18
19							19
20							20
21	INTANGIBLE	P90		2,404,221	978,866	1,425,354	21
22							22
23	TOTAL DEPRECIATION EXPENSE		403	35,016,724	13,387,642	21,629,082	23
24							24
25							25
26							26
27							27
28							28
29							29
30							30
31	BIG STONE EXPENSE OFFSETS	P10		0	0	0	31
32							32
33							33
34	SPIRITWOOD AMORTIZATION	P10	406	0	0	0	34
35							35
36							36
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LINE NO	ITEM	ALLOC	FERC ACCOUNTS	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	GENERAL TAXES	NEPIS		11,303,652	3,936,734	7,366,918	1
2	GENERAL TAXES (Direct FERC)	Direct FERC		1,779,231	0	1,779,231	2
3	TOTAL GENERAL TAXES		408.1	13,082,883	3,936,734	9,146,149	3
4							4
5	NET OPERATING INCOME BEFORE TAX (NOBT)			92,112,912	11,071,955	81,040,957	5
6							6
7	INVESTMENT TAX CREDIT						7
8	AMORTIZE PRIOR YEARS CREDIT	EPIS		(3,180,509)	(1,183,682)	(1,996,827)	8
9	DEBITS UTILIZED	EPIS		0	0	0	9
10							10
11	TOTAL INVESTMENT TAX CREDIT		411.4	(3,180,509)	(1,183,682)	(1,996,827)	11
12							12
13	DEFERRED INCOME TAXES						13
14	ITEMS SOUTH DAKOTA FLOWS THROUGH						14
15	FEDERAL	NPMNR		0	0	0	15
16	MINNESOTA	NPISM		0	0	0	16
17	NORTH DAKOTA	NPISN		0	0	0	17
18							18
19	SUBTOTAL			0	0	0	19
20							20
21	ALL OTHER						21
22							22
23	FEDERAL- transfer from Current Income Taxes - NOL			0	0	0	23
24	FEDERAL (NEPIS)	NEPIS		(8,614,615)	(3,000,220)	(5,614,394)	24
25	FEDERAL			(8,614,615)	(3,000,220)	(5,614,394)	25
26							26
27	MINNESOTA- transfer from Current Income Taxes - NOL			0	0	0	27
28	MINNESOTA (NPISM)	NPISM		1,389,019	0	1,389,019	28
29	MINNESOTA			1,389,019	0	1,389,019	29
30							30
31	NORTH DAKOTA- transfer from Current Income Taxes - NOL			515,450	515,545	(95)	31
32	NORTH DAKOTA (NPISN)	NPISN		845,206	845,206	0	32
33	NORTH DAKOTA			1,359,354	1,360,751	(1,397)	33
34							34
35	SUBTOTAL			(5,866,242)	(1,639,469)	(4,226,773)	35
36							36
37	TOTAL DEFERRED INCOME TAXES		410.1-410.2, 411.1-411.2	(5,866,242)	(1,639,469)	(4,226,773)	37
38							38
39							39
40	CURRENT INCOME TAXES						40
41	FEDERAL- transfer to Deferred Income Taxes - NOL			0	0	0	41
42	FEDERAL CURRENT INCOME TAX			18,096,507	2,408,839	15,687,668	42
43	FEDERAL INCOME TAXES			18,096,507	2,408,839	15,687,668	43
44							44
45	MINNESOTA- transfer to Deferred Income Taxes - NOL			0	0	0	45
46	MINNESOTA CURRENT INCOME TAX			4,944,670	0	4,944,670	46
47	MINNESOTA INCOME TAXES			4,944,670	0	4,944,670	47
48							48
49	NORTH DAKOTA - transfer to Deferred Income Taxes - NOL			(515,450)	(515,545)	95	49
50	NORTH DAKOTA CURRENT INCOME TAX			515,567	515,545	22	50
51	NORTH DAKOTA INCOME TAXES			117	(0)	117	51
52							52
53	TOTAL CURRENT INCOME TAXES		409.1	23,041,293	2,408,838	20,632,455	53
54							54
55	TOTAL INCOME TAXES			13,994,542	(414,313)	14,408,855	55
56							56
57							57
58	NET OPERATING INCOME			78,118,369	11,486,268	66,632,101	58
59							59
60	AFDC	CWIPLT		2,027,574	0	2,027,574	60
61	AFDC - MN Only	CWIPLT		0	0	0	61
62	AFDC - SD Only	CWIPLT		0	0	0	62
63	Total AFDC	CWIPLT	419.1	2,027,574	0	2,027,574	63
64							64
65	TOTAL AVAILABLE FOR RETURN			80,145,944	11,486,268	68,659,675	65
66							66
67							67
68	RATE OF RETURN ON RATE BASE			10.32%	5.14%	12.41%	68
69							69
70							70
71							71
72							72
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE					1
2						2
3	NET OPERATING INCOME BEFORE TAX (NOBT)		92,112,912	11,071,955	81,040,957	3
4	LESS: INTEREST COST	CALCULATED BY JURISDICTION	19,454,157	5,694,305	13,759,852	4
5						5
6	NET INCOME BEFORE TAX		72,658,755	5,377,651	67,281,104	6
7						7
8	FEDERAL SCHEDULE M ADJUSTMENTS:					8
9	ADDITIONAL TAX DEPRECIATION	NEPIS	(9,985,336)	(3,477,603)	(6,507,734)	9
10	COST TO REMOVE	NEPIS	500,000	174,135	325,865	10
11	DIRECTLY ASSIGNED SCHEDULE M ITEMS	NEPIS DIRECTLY ASSIGNED TO JURISDICTION	0	0	0	11
12	ACCRUED VACATION PAY	NEPIS	0	0	0	12
13	CHARGES - OPERATING RESERVES	NEPIS	8,193,954	2,853,716	5,340,237	13
14	PROVISIONS - OPERATING RESERVES	NEPIS	(2,710,794)	(944,091)	(1,766,703)	14
15	UNBILLED REVENUES	NEPIS	0	0	0	15
16	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	0	0	0	16
17	OTHER SCHEDULE M ITEMS	NEPIS	(14,973,148)	(5,214,713)	(9,758,435)	17
18						18
19	SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS		(18,975,325)	(6,608,555)	(12,366,770)	19
20						20
21	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		91,634,080	11,986,205	79,647,874	21
22						22
23	LESS:					23
24	MINNESOTA STATE INCOME TAXES	PER MINNESOTA STATE TAX CALCULATION	4,944,670	0	4,944,670	24
25	NORTH DAKOTA STATE INCOME TAXES	PER NORTH DAKOTA STATE TAX CALCULATION	515,567	515,545	22	25
26						26
27	FEDERAL TAXABLE INCOME		86,173,843	11,470,660	74,703,183	27
28	FEDERAL TAX RATE		21.00%	21.00%	21.00%	28
29						29
30	FEDERAL INCOME TAX BEFORE CREDITS		18,096,507	2,408,839	15,687,668	30
31	INVESTMENT TAX CREDIT - DEBITS UTILIZED	EPIS	0	0	0	31
32	FEDERAL INCOME TAXES before transfer to Deferred due to NOL		18,096,507	2,408,839	15,687,668	32
33	Less Current Federal Income Taxes Transferred to Deferred Income Taxes due to NOL		0	0	0	33
34	FEDERAL INCOME TAXES		18,096,507	2,408,839	15,687,668	34
35						35
36						36
37						37
38						38
39						39
40						40
41						41
42						42
43						43
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61						61

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE					1
2						2
3	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		76,452,488	0	76,452,486	3
4						4
5	MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					5
6	PAYSOP ADJUSTMENT	NEPIS	0	0	0	6
7	CHANGE IN EXCESS TAX DEPRECIATION - M	NEPIS	(25,918,377)	0	(25,918,377)	7
8	CHANGE IN ACRS - ORDINARY LOSS	NEPIS	0	0	0	8
9	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	0	0	0	9
10	MISCELLANEOUS ADJUSTMENTS TO FED SC	NEPIS	(78,295)	0	(78,295)	10
11						11
12	TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M		(25,996,671)	0	(25,996,671)	12
13						13
14	MINNESOTA TAXABLE INCOME		50,455,814	0	50,455,814	14
15	MINNESOTA TAX RATE		9.80%	0.00%	9.80%	15
16						16
17	MINNESOTA INCOME TAX prior to transfer to Deferred Income Tax due to NOL		4,944,670	0	4,944,670	17
18	Minnesota Current Income Tax transfer to Deferred Income Tax due to NOL		0	0	0	18
19	MINNESOTA INCOME TAX		4,944,670	0	4,944,670	19
20						20
21						21
22						22
23						23
24						24
25						25
26						26
27	DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE					27
28						28
29	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		11,986,205	11,986,205	0	29
30						30
31	NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					31
32	CHANGE IN EXCESS TAX DEPRECIATION - ND	NEPIS	(2,457)	(1,688)	(769)	32
33	CHANGE IN ACRS - ORDINARY LOSS - ND	NEPIS	0	0	0	33
34	CHANGE IN INCOME FROM ADR PROPERTY	NEPIS	0	0	0	34
35	MISCELLANEOUS ADJUSTMENTS TO FED SC	NEPIS	(4,562)	(3,134)	(1,427)	35
36						36
37	TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M		(7,019)	(4,823)	(2,196)	37
38						38
39	SUBTOTAL		11,979,186	11,981,383	(2,196)	39
40	DEDUCTION OF FEDERAL INCOME TAXES		0	0	0	40
41						41
42	NORTH DAKOTA TAXABLE INCOME		11,979,186	11,931,383	47,804	42
43	NORTH DAKOTA TAX RATE		4.31%	4.31%	4.31%	43
44						44
45	NORTH DAKOTA INCOME TAX prior to transfer to Deferred Income Tax due to NOL		515,567	515,545	22	45
46	North Dakota Current Income Tax transfer to Deferred Income Tax due to NOL		(515,450)	(515,545)	95	46
47	NORTH DAKOTA INCOME TAX		117	(0)	117	47
48						48
49						49
50						50
51						51
52						52
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63						63
64						64

ALLOCATION FACTORS

LINE NO	ITEM	FACTOR	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	MWH CONSUMPTION AT GENERATORS - PAR	E1	4,717,027	1,682,012	3,035,015	1
2	PERCENTAGE		100.000000%	35.658308%	64.341692%	2
3						3
4	MWH CONSUMPTION AT GENERATORS - TOT	E2	5,271,408	1,980,855	3,290,553	4
5	PERCENTAGE		100.000000%	37.577342%	62.422658%	5
6						6
7	GENERATION DEMAND FACTOR	D1	740,845	295,156	445,689	7
8	PERCENTAGE		100.000000%	39.840452%	60.159548%	8
9						9
10	TRANSMISSION DEMAND FACTOR	D2	745,364	295,156	450,208	10
11	PERCENTAGE		100.000000%	39.598907%	60.401093%	11
12						12
13	DISTRIBUTION - PRIMARY DEMAND FACTOR	D3	879,600	403,477	476,123	13
14	PERCENTAGE		100.000000%	45.870509%	54.129491%	14
15						15
16	DISTRIBUTION - SECONDARY DEMAND FACTOR	D4	1,168,271	561,014	607,257	16
17	PERCENTAGE		100.000000%	48.020879%	51.979121%	17
18						18
19	CUSTOMER OR METER FACTORS					19
20	TOTAL RETAIL CUSTOMERS	C1	133,437	59,557	73,880	20
21	PERCENTAGE		100.000000%	44.633048%	55.366952%	21
22						22
23	RETAIL SERVICE LOCATIONS	C2	140,167	62,754	77,413	23
24	PERCENTAGE		100.000000%	44.770880%	55.229120%	24
25						25
26	SECONDARY SERVICE LOCATIONS	C3	140,091	62,738	77,353	26
27	PERCENTAGE		100.000000%	44.783748%	55.216252%	27
28						28
29	STREET LIGHTING FACTOR	C4	5,464,004	2,381,279	3,082,725	29
30	PERCENTAGE		100.000000%	43.581209%	56.418791%	30
31						31
32	AREA LIGHTING FACTOR	C5	4,786,865	2,477,820	2,309,045	32
33	PERCENTAGE		100.000000%	51.762897%	48.237103%	33
34						34
35	METER FACTOR	C6	52,603,325	23,503,024	29,100,301	35
36	PERCENTAGE		100.000000%	44.679731%	55.320269%	36
37						37
38	METER READING FACTOR	C7	182,297	77,918	104,379	38
39	PERCENTAGE		100.000000%	42.742338%	57.257662%	39
40						40
41	SYSTEM SERVICE LOCATIONS	C8	140,192	62,757	77,435	41
42	PERCENTAGE		100.000000%	44.765037%	55.234963%	42
43						43
44	LOAD MANAGEMENT FACTOR	C9	42,771	18,627	24,144	44
45	PERCENTAGE		100.000000%	43.550537%	56.449463%	45
46						46
47						47
48						48
49						49
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60						60

LINE NO	ITEM	ALLOCATION FACTORS FACTOR	TOTAL COMPANY	NORTH DAKOTA	OTHER	LINE NO
1	GROSS PLANT IN SERVICE					1
7	PRODUCTION PLANT	P10	430,579,725	154,188,767	276,390,957	2
8	PERCENTAGE		100.000000%	35.809575%	64.190425%	3
9						4
10	DISTRIBUTION PLANT	P60	497,992,871	228,593,947	269,398,824	5
11	PERCENTAGE		100.000000%	45.903056%	54.096944%	6
12						7
13	GENERAL PLANT	P90	88,619,779	36,081,097	52,538,682	8
14	PERCENTAGE		100.000000%	40.714497%	59.285503%	9
15						10
16						11
17	ELECTRIC PLANT IN SERVICE	EPIS	1,422,111,765	529,263,615	892,848,150	12
18	PERCENTAGE		100.000000%	37.216738%	62.783262%	13
19						14
20	NET ELECTRIC PLANT IN SERVICE	NEPIS	782,632,470	272,568,167	510,064,303	15
21	PERCENTAGE		100.000000%	34.827097%	65.172903%	16
22						17
23	OPERATION AND MAINTENANCE EXPENSE					18
24	PRODUCTION EXPENSE (EXCL ENERGY)	OXPD	21,678,726	7,873,398	13,805,328	19
26	PERCENTAGE		100.000000%	36.318544%	63.681456%	20
27						21
28	DISTRIBUTION EXPENSE	OXD	16,917,384	7,680,921	9,236,463	22
29	PERCENTAGE		100.000000%	45.402533%	54.597467%	23
30						24
31	CUSTOMER ACCOUNTS EXPENSE	OXC	13,849,926	6,091,579	7,758,346	25
32	PERCENTAGE		100.000000%	43.982759%	56.017241%	26
33						27
34	CUSTOMER SERVICE & INFORMATION EXPE	OXI	3,097,502	1,382,509	1,714,992	28
35	PERCENTAGE		100.000000%	44.633048%	55.366952%	29
36						30
37	OTHER DEFERRED INCOME TAX FACTOR					31
38	MINNESOTA	NPISM	447,239,409	0	447,239,409	32
39	PERCENTAGE		100.000000%	0.000000%	100.000000%	33
40						34
41	NORTH DAKOTA	NPISN	272,568,167	272,568,167	0	35
42	PERCENTAGE		100.000000%	100.000000%	0.000000%	36
43						37
44	EXCLUDING SOUTH DAKOTA	NPMNR	719,807,576	272,568,167	447,239,409	38
45	PERCENTAGE		100.000000%	37.866810%	62.133190%	39
46						40
47	LONG-TERM CWIP RATIO (W/AFDC)	CWIPLT	28,591,925	0	28,591,925	41
48	PERCENTAGE		100.000000%	0.000000%	100.000000%	42
49						43
50	REVENUE	R10	359,865,140	122,589,268	237,275,872	44
51	PERCENTAGE		100.000000%	34.065336%	65.934664%	45
52						46
53	LABOR AND RELATED EXPENSE	LRE	140,669,570	53,337,957	87,331,613	47
54	PERCENTAGE		100.000000%	37.917196%	62.082804%	48
55						49
56	TOTAL O & M EXPENSE	OX				50
57	PERCENTAGE					51
58						52
59						53
60						54
61						55
62						56
63						57
64						58
65						59
66						60

LINE NO	ITEM	AMOUNT	AMOUNT AS		COST OF CAPITAL	RATE OF RETURN	LINE NO
			A PERCENT OF TOTAL				
1	<u>CAPITAL STRUCTURE - RATE OF RETURN</u>						1
2							2
3							3
4	LONG-TERM DEBT	510,697,554	47.50%		5.38%	2.55%	4
5							5
6	PREFERRED STOCK	0	0.00%		0.00%	0.00%	6
7							7
8	COMMON EQUITY	564,383,902	52.50%		10.30%	5.41%	8
9							9
10							10
11	TOTAL	<u>1,075,081,457</u>	<u>100.00%</u>			<u>7.96%</u>	11
12							12
13							13
14							14
15							15
16							16
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LINE NO	ITEM	ALLOCATION	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS					1
2						2
3	REVENUES					3
4	COMPUTER MAINTAINED BILLINGS		322,408,326	116,394,113	206,014,212	4
5	MANUALLY MAINTAINED BILLINGS		30,668,230	11,071,679	19,596,551	5
6	COST OF ENERGY REVENUES	R10	7,871,578	(4,463,840)	12,335,418	6
7	SALES FOR RESALE		190,597	5,646	184,950	7
8	RENT FROM ELECTRIC PROPERTY		568,008	197,821	370,187	8
9	MISCELLANEOUS		2,576,976	897,486	1,679,490	9
10	ITA DEFICIENCY PAYMENTS		1,773,638	617,707	1,155,932	10
11	WHEELING		439,772	0	439,772	11
12	LOAD CONTROL AND DISPATCH		21,716,925	7,563,374	14,153,550	12
13	RENT FROM ELECTRIC PROPERTY - BIG STONE		11,825	4,118	7,707	13
14	RENT FROM ELECTRIC PROPERTY - COYOTE		9,800	3,413	6,387	14
15	PROFIT ON MATERIALS AND SUPPLIES		0	0	0	15
16	RUBBER GOODS TESTING		28,101	9,787	18,314	16
17	RESIDENTIAL CONSERVATION SERVICES		2,676	0	2,676	17
18						18
19	TOTAL REVENUES		388,266,451	132,301,305	255,965,147	19
20						20
21	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION					21
22	COMPUTER MAINTAINED BILLINGS		N/A	43.4	N/A	22
23	MANUALLY MAINTAINED BILLINGS		N/A	41.3	N/A	23
24	COST OF ENERGY REVENUES		N/A	127.7	N/A	24
25	SALES FOR RESALE		N/A	23.1	N/A	25
26	RENT FROM ELECTRIC PROPERTY		N/A	-92.4	N/A	26
27	MISCELLANEOUS		N/A	34.9	N/A	27
28	ITA DEFICIENCY PAYMENTS		N/A	48.4	N/A	28
29	WHEELING		N/A	35.8	N/A	29
30	LOAD CONTROL AND DISPATCH		N/A	27.9	N/A	30
31	RENT FROM ELECTRIC PROPERTY - BIG STONE		N/A	39.3	N/A	31
32	RENT FROM ELECTRIC PROPERTY - COYOTE		N/A	39.3	N/A	32
33	PROFIT ON MATERIALS AND SUPPLIES		N/A	39.3	N/A	33
34	RUBBER GOODS TESTING		N/A	39.3	N/A	34
35	RESIDENTIAL CONSERVATION SERVICES		N/A	39.3	N/A	35
36						36
37						37
38	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)					38
39	COMPUTER MAINTAINED BILLINGS		13,992,521,342	5,051,504,523	8,941,016,819	39
40	MANUALLY MAINTAINED BILLINGS		1,266,597,883	457,260,331	809,337,552	40
41	COST OF ENERGY REVENUES		809,500,370	(570,108,920)	1,379,609,290	41
42	SALES FOR RESALE		4,395,161	130,236	4,264,925	42
43	RENT FROM ELECTRIC PROPERTY		(52,489,606)	(18,280,606)	(34,209,000)	43
44	MISCELLANEOUS		89,988,014	31,340,213	58,647,801	44
45	ITA DEFICIENCY PAYMENTS		85,844,099	29,897,008	55,947,092	45
46	WHEELING		15,726,231	0	15,726,231	46
47	LOAD CONTROL AND DISPATCH		605,902,201	211,018,146	394,884,056	47
48	RENT FROM ELECTRIC PROPERTY - BIG STONE		486,732	161,855	324,878	48
49	RENT FROM ELECTRIC PROPERTY - COYOTE		403,367	134,133	269,234	49
50	PROFIT ON MATERIALS AND SUPPLIES		0	0	0	50
51	RUBBER GOODS TESTING		1,156,622	384,615	772,007	51
52	RESIDENTIAL CONSERVATION SERVICES		114,533	0	114,533	52
53						53
54						54
55	TOTAL DOLLAR DAYS		16,820,146,950	5,193,441,503	11,626,705,447	55
56						56
57	AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)					57
58			43.3	39.3	45.4	58
59						59
60						60

LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF 42.8 OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS-MINNESOTA JURISDICTION						2
3	FUEL - COAL E2	28,396,748	77,799	15.5	27.3	2,123,143	3
4							4
5	FUEL - OIL E1	33,457	92	11.2	31.6	2,895	5
6							6
7	PURCHASED POWER	37,542,735	102,857	31.6	11.2	1,154,053	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE LRE	3,101,105	8,496	15.1	27.7	235,259	9
10							10
11	ALL OTHER O&M EXPENSE	77,990,906	213,674	13.1	29.7	6,347,327	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	4,438,028	12,159	299.6	-256.8	(3,122,853)	13
14							14
15	COAL CONVERSION TAXES	228,732	627	33.3	9.5	5,941	15
16							16
17	FEDERAL INCOME TAXES	10,116,054	27,715	0.0	42.8	1,186,211	17
18							18
19	STATE INCOME TAXES	3,193,159	8,748	0.0	42.8	374,431	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES	0	0	0.0	42.8	0	21
22							22
23	INCREMENTAL STATE INCOME TAXES	0	0	0.0	42.8	0	23
24							24
25	BANK BALANCES NEPIS					4,046	25
26							26
27	SPECIAL DEPOSITS NEPIS					3,096	27
28							28
29	WORKING FUNDS NEPIS					5,145	29
30							30
31	TAX COLLECTIONS AVAIL - FICA WITHHOLDING LRE	(2,664,137)	(7,299)	0.0		0	31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING LRE	(4,336,071)	(11,880)	0.0		0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLDING R10 ASSIGN TO JURIS	(1,900,000)	(5,205)	1.9		(9,942)	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLDING R10 ASSIGN TO JURIS	0	0	69.1		0	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES R10	(9,417,230)	(25,801)	13.0		(334,118)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE TAX R10	(1,649,127)	(4,518)	23.8		(107,632)	41
42							42
43							43
44	CASH WORKING CAPITAL REQUIREMENT - MINNESOTA					7,867,102	44
45							45
46							46
47							47
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51							51
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LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF 39.3 OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS-NORTH DAKOTA JURISDICTION						2
3	FUEL - COAL E2	19,990,895	54,770	15.5	23.8	1,302,968	3
4							4
5	FUEL - OIL E1	21,698	59	11.2	28.1	1,669	5
6							6
7	PURCHASED POWER	26,355,139	72,206	31.6	7.7	557,429	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXP LRE	2,278,150	6,242	15.1	24.2	150,982	9
10							10
11	ALL OTHER O&M EXPENSE	55,259,091	151,395	13.1	26.2	3,967,406	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	3,743,783	10,257	299.6	-260.3	(2,670,241)	13
14							14
15	COAL CONVERSION TAXES	192,951	529	33.3	6.0	3,161	15
16							16
17	FEDERAL INCOME TAXES	2,408,839	6,600	0.0	39.3	259,363	17
18							18
19	STATE INCOME TAXES	0	0	0.0	39.3	0	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES	0	0	0.0	39.3	0	21
22							22
23	INCREMENTAL STATE INCOME TAXES	0	0	0.0	39.3	0	23
24							24
25	BANK BALANCES NEPIS					3,413	25
26							26
27	SPECIAL DEPOSITS NEPIS					2,612	27
28							28
29	WORKING FUNDS NEPIS					4,340	29
30							30
31	TAX COLLECTIONS AVAIL - FICA WITHH LRE	(1,957,142)	(5,362)	0.0		0	31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL W LRE	(3,185,387)	(8,727)	0.0		0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITH R10 ASSIGN TO JURIS	0	0	1.9		0	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITH R10 ASSIGN TO JURIS	(185,000)	(507)	69.1		(34,998)	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE R10	(143)	(0)	23.8		(9)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRAN R10	0	0	0.0		0	41
42							42
43							43
44	CASH WORKING CAPITAL REQUIREMENT - NORTH DAKOTA					3,548,095	44
45							45
46							46
47							47
48							48
49							49
50							50
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LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF 66.4 OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD LAG FACTORS-SOUTH DAKOTA JURISDICTION						2
3	FUEL - COAL	4,772,381	13,075	15.5	50.9	665,388	3
4							4
5	FUEL - OIL	5,843	15	11.2	55.2	853	5
6							6
7	PURCHASED POWER	6,310,284	17,288	31.6	34.8	601,984	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE	533,931	1,463	15.1	51.3	75,028	9
10							10
11	ALL OTHER O&M EXPENSE	12,952,062	35,485	13.1	53.3	1,891,558	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	862,913	2,364	299.6	-233.2	(551,402)	13
14							14
15	COAL CONVERSION TAXES	44,474	122	33.3	33.1	4,031	15
16							16
17	FEDERAL INCOME TAXES	671,032	1,838	0.0	66.4	122,073	17
18							18
19	STATE INCOME TAXES	0	0	0.0	66.4	0	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES	0	0	0.0	66.4	0	21
22							22
23	INCREMENTAL STATE INCOME TAXES	0	0	0.0	66.4	0	23
24							24
25	BANK BALANCES					787	25
26							26
27	SPECIAL DEPOSITS					602	27
28							28
29	WORKING FUNDS					1,000	29
30							30
31	TAX COLLECTIONS AVAIL - FICA WITHHOLDIN	(458,696)	(1,257)	0.0		0	31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL WITHHO	(746,561)	(2,045)	0.0		0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLD	0	0	1.9		0	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLD	0	0	69.1		0	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES	(1,268,662)	(3,476)	13.7		(47,479)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE T	0	0	0.0		0	41
42							42
43							43
44	CASH WORKING CAPITAL REQUIREMENT - SOUTH DAKOTA					2,764,423	44
45							45
46							46
47							47
48							48
49							49
50							50
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LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF 28.2 OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD LAG FACTORS-FERC JURISDICTION						2
3	FUEL - COAL	E2	39,309	108	15.5	12.7	3
4							4
5	FUEL - OIL	E1	51	0	11.2	17.0	5
6							6
7	PURCHASED POWER		52,163	143	31.6	-3.4	7
8						(483)	8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE	LRE	95,037	260	15.1	13.1	9
10							10
11	ALL OTHER O&M EXPENSE		2,154,378	5,902	13.1	15.1	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)		1,704,902	4,671	299.6	-271.4	13
14						(1,267,863)	14
15	COAL CONVERSION TAXES		87,869	241	33.3	-5.1	15
16						(1,233)	16
17	FEDERAL INCOME TAXES		4,900,607	13,426	0.0	28.2	17
18							18
19	STATE INCOME TAXES		1,751,510	4,799	0.0	28.2	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES		0	0	0.0	28.2	21
22							22
23	INCREMENTAL STATE INCOME TAXES		0	0	0.0	28.2	23
24							24
25	BANK BALANCES	NEPIS					25
26						1,554	26
27	SPECIAL DEPOSITS	NEPIS					27
28						1,190	28
29	WORKING FUNDS	NEPIS					29
30						1,976	30
31	TAX COLLECTIONS AVAIL - FICA WITHHOLDIN	LRE	(81,646)	(224)	0.0		31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL WITHHO	LRE	(132,885)	(364)	0.0		33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLD	R10 ASSIGN TO JURIS	0	0	1.9		35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLD	R10 ASSIGN TO JURIS	0	0	69.1		37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES	R10	0	0	0.0		39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE T	R10	0	0	0.0		41
42							42
43							43
44	TOTAL CASH WORKING CAPITAL REQUIREMENT - FERC					(656,977)	44
45							45
46							46
47							47
48							48
49							49
50							50
51							51
52							52
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LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF 43.3 OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD LAG FACTORS - TOTAL CO.						2
3	FUEL - COAL	E2				4,092,866	3
4							4
5	FUEL - OIL	E1				5,420	5
6							6
7	PURCHASED POWER					2,312,983	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE	LRE				464,678	9
10							10
11	ALL OTHER O&M EXPENSE					12,295,451	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)					(7,612,359)	13
14							14
15	COAL CONVERSION TAXES					11,900	15
16							16
17	FEDERAL INCOME TAXES					1,946,269	17
18							18
19	STATE INCOME TAXES					509,753	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES					0	21
22							22
23	INCREMENTAL STATE INCOME TAXES					0	23
24							24
25	BANK BALANCES	NEPIS				9,800	25
26							26
27	SPECIAL DEPOSITS	NEPIS				7,500	27
28							28
29	WORKING FUNDS	NEPIS				12,462	29
30							30
31	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	LRE				0	31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	LRE				0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLDING	R10 ASSIGN TO JURIS				(9,942)	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLDING	R10 ASSIGN TO JURIS				(34,998)	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	R10				(381,607)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE TAX	R10				(107,532)	41
42							42
43							43
44	CASH WORKING CAPITAL REQUIREMENT - TOTAL COMPANY					13,522,643	44
45							45
46							46
47							47
48							48
49							49
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LINE NO	ITEM	ALLOC	MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL COMPANY	LINE NO
1	ELECTRIC PLANT IN SERVICE		640,243,183	529,263,615	122,404,512	130,200,455	1,422,111,765	1
2	ACCUMULATED DEPRECIATION		(317,130,099)	(256,695,448)	(59,579,619)	(6,074,130)	(639,479,296)	2
3	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED IT		323,113,084	272,568,167	62,824,894	124,126,325	782,632,470	3
4	NET CAPITALIZED ITEMS - BIG STONE PLANT		0	0	0	0	0	4
5	NET ELECTRIC PLANT IN SERVICE		323,113,084	272,568,167	62,824,894	124,126,325	782,632,470	5
6	PLANT HELD FOR FUTURE USE		13,883	13,044	2,816	114	29,657	6
7	CONSTRUCTION WORK IN PROGRESS		15,242,434	271,748	0	95,853,903	125,054,506	7
8	MATERIALS AND SUPPLIES		9,433,264	7,946,645	1,820,947	64,181	19,265,037	8
9	FUEL STOCKS		6,534,970	4,430,805	1,122,620	11,281	12,099,676	9
10	PREPAYMENTS		(15,102,001)	(12,739,580)	(2,936,376)	(5,801,548)	(36,579,505)	10
11	CUSTOMER ADVANCES		(418,629)	(353,143)	(81,397)	(160,820)	(1,013,988)	11
12	CASH WORKING CAPITAL		7,867,102	3,548,095	2,764,423	(656,977)	13,522,643	12
13	ACCUMULATED DEFERRED INCOME TAXES		(42,486,732)	(52,379,715)	(3,648,399)	(39,901,114)	(138,415,960)	13
14	UNAMORTIZED BALANCE - SPIRITWOOD		0	0	0	0	0	14
15	UNAMORTIZED RATE CASE EXPENSE		0	0	0	0	0	15
16	TOTAL AVERAGE RATE BASE		304,197,175	223,306,067	61,869,527	173,535,346	776,594,536	16
17							***	17
18								18
19								19
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59								59
60								60

*** NOTE: TOTAL AVERAGE RATE BASE WILL NOT ADD ACROSS BECAUSE CWIP IS NOT ALLOCATED TO ALL JURISDICTIONS.

LINE NO	ITEM	ALLOC		MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL COMPANY	LINE NO
1	CONST WORK-IN-PROGRESS - Direct Assigned			0					1
2	PRODUCTION PLANT - Direct MN	P10	Directly Assigned to Jurisdiction	0	0	0	0	0	2
3	PRODUCTION PLANT - Direct ND	P10		0	0	0	0	0	3
4	PRODUCTION PLANT - Direct SD	P10		0	0	0	0	0	4
5	PRODUCTION PLANT - Direct FERC	Direct FERC		0	0	0	0	0	5
6	TRANSMISSION PLANT - Direct MN	D2	Directly Assigned to Jurisdiction	0	0	0	0	0	6
7	TRANSMISSION PLANT - Direct ND	D2		0	0	0	0	0	7
8	TRANSMISSION PLANT - Direct SD	D2		0	0	0	0	0	8
9	TRANSMISSION PLANT - Direct FERC	Direct FERC		0	0	0	95,776,331	95,776,331	9
10	DISTRIBUTION PLANT - Direct MN	P60	Directly Assigned to Jurisdiction	0	0	0	0	0	10
11	DISTRIBUTION PLANT - Direct ND	P60		0	0	0	0	0	11
12	DISTRIBUTION PLANT - Direct SD	P60		0	0	0	0	0	12
13	DISTRIBUTION PLANT - Direct FERC	Direct FERC		0	0	0	0	0	13
14	GENERAL PLANT - Direct MN	P90	Directly Assigned to Jurisdiction	0	0	0	0	0	14
15	GENERAL PLANT - Direct ND	P90		0	0	0	0	0	15
16	GENERAL PLANT - Direct SD	P90		0	0	0	0	0	16
17	GENERAL PLANT - Direct FERC	Direct FERC		0	0	0	0	0	17
18	INTANGIBLE PLANT - Direct MN	P90	Directly Assigned to Jurisdiction	0	0	0	0	0	18
19	INTANGIBLE PLANT - Direct ND	P90		0	0	0	0	0	19
20	INTANGIBLE PLANT - Direct SD	P90	Directly Assigned to Jurisdiction	0	0	0	0	0	20
21	INTANGIBLE PLANT - Direct FERC	Direct FERC		0	0	0	0	0	21
22	TOTAL CWIP - Direct Assigned		ALLOWED ONLY IN MN & FERC	0	0	0	95,776,331	95,776,331	22
23				0					23
24				0					24
25	CONST WORK-IN-PROGRESS - SHORT-TERM			0					25
26	PRODUCTION PLANT	P10		0	0	0	0	0	26
27	TRANSMISSION PLANT	D2		346,123	271,748	0	5,006	686,250	27
28	DISTRIBUTION PLANT	P60		0	0	0	0	0	28
29	GENERAL PLANT	P90		0	0	0	0	0	29
30	INTANGIBLE PLANT	P90		0	0	0	0	0	30
31				0					31
32	TOTAL CWIP - SHORT-TERM		ALLOWED ONLY IN MN, ND & FERC	346,123	271,748	0	5,006	686,250	32
33				0					33
34				0					34
35	CONST WORK-IN-PROGRESS - LONG TERM			0					35
36	PRODUCTION PLANT (AFUDC Projects)	P10		7,676,438	0	0	12,289	14,041,071	36
37	PRODUCTION PLANT (Rider Projects)	P10		0	0	0	0	0	37
38	TRANSMISSION PLANT (AFUDC Projects)	D2		2,953,225	0	0	42,711	5,855,294	38
39	TRANSMISSION PLANT (Rider Projects)	D2		0	0	0	0	0	39
40	DISTRIBUTION PLANT	P60		508,542	0	0	2,706	1,149,148	40
41	GENERAL PLANT	P90		798,775	0	0	3,158	1,603,969	41
42	INTANGIBLE PLANT	P90		2,959,331	0	0	11,702	5,942,443	42
43				0					43
44	TOTAL CWIP - LONG TERM - AFUDC Projects		ALLOWED ONLY IN MN & FERC	14,896,311	0	0	72,566	28,591,925	44
45	TOTAL CWIP - LONG TERM - Rider Projects			0	0	0	0	0	45
46				0					46
47				0					47
48	TOTAL CONSTRUCTION WORK-IN-PROGRESS			15,242,434	271,748	0	95,853,903	125,054,506	48
49				0					49
50				0					50
51	MATERIALS & SUPPLIES			0					51
52	PRODUCTION	P10		2,995,295	1,961,911	516,731	4,795	5,478,732	52
53	TRANSMISSION	D2		2,749,009	2,150,299	503,334	39,758	5,450,400	53
54	DISTRIBUTION	P60		3,688,960	3,826,435	800,881	19,628	8,335,906	54
55				0					55
56	TOTAL MATERIALS AND SUPPLIES	154, 158.1		9,433,264	7,946,645	1,820,947	64,181	19,265,037	56
57				0					57
58				0					58
59	FUEL STOCKS			0					59
60	COAL STOCKS	E1		5,124,248	3,323,221	864,322	7,836	9,319,627	60
61	FUEL OIL STOCKS	D1		1,410,722	1,107,584	258,298	3,445	2,780,049	61
62				0					62
63	TOTAL FUEL STOCKS	1510		6,534,970	4,430,805	1,122,620	11,281	12,099,676	63
64				0					64
65				0					65
66	PREPAYMENTS	NEPIS	128, 228.3	(15,102,001)	(12,739,580)	(2,936,376)	(5,801,548)	(36,579,505)	66
67				0					67
68	CUSTOMER ADVANCES	NEPIS	235, 253	(418,629)	(353,143)	(81,397)	(160,820)	(1,013,988)	68
69				0					69
70	CASH WORKING CAPITAL	OX	SEPARATELY CALCULATED BY JURISDICTION	7,867,102	3,548,095	2,764,423	(656,977)	13,522,643	70
71				0					71
72				0					72
73				0					73
74				0					74
75				0					75
76				0					76
77				0					77

LINE NO	ITEM	ALLOC	MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL COMPANY	LINE NO
1			0					1
2	ACCUMULATED DEFERRED INCOME TAXES		0					2
3	<u>ITEMS SD FLOWS THROUGH</u>		0					3
4	FEDERAL	NPMNR	195,505	164,922	0	75,105	435,531	4
5	MINNESOTA	NPISM	52,067	0	0	20,002	72,069	5
6	NORTH DAKOTA	NPISN	0	35,772	0	0	35,772	6
7	SUBTOTAL		247,571	200,693	0	95,106	543,371	7
8			0					8
9	<u>ALL OTHER</u>		0					9
10	FEDERAL	NEPIS	(18,763,987)	(15,828,717)	(3,648,399)	(7,208,327)	(45,449,430)	10
11	FEDERAL (Direct FERC)	Direct FERC	0	0	0	(23,579,516)	(23,579,516)	11
12	MINNESOTA	NPISM	(23,970,316)	0	0	(9,208,378)	(33,178,694)	12
13	NORTH DAKOTA	NPISN	0	(36,751,691)	0	0	(36,751,691)	13
14			0					14
15	SUBTOTAL		(42,734,303)	(52,580,408)	(3,648,399)	(39,996,221)	(138,959,331)	15
16			0					16
17	TOTAL ACCUMULATED DEFERRED INCOME TAXES	190, 255, 281-283	(42,486,732)	(52,379,715)	(3,648,399)	(39,901,114)	(138,415,960)	17
18			0					18
19			0					19
20	UNAMORTIZED BALANCE - SPIRITWOOD PLAN	P10	0	0	0	0	0	20
21			0					21
22			0					22
23	UNAMORTIZED RATE CASE EXPENSES	R10	0	0	0	0	0	23
24			0					24
25			0					25
26			0					26
27			0					27
28	TOTAL AVERAGE RATE BASE		304,197,175	223,306,067	61,869,527	173,535,346	776,594,536	28
29			0					29
30			0					30
31			0					31
32			0					32
33			0					33
34			0					34
35			0					35
36			0					36
37			0					37
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42			0					42
43			0					43
44			0					44
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47			0					47
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52			0					52
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56			0					56
57			0					57
58			0					58
59			0					59
60			0					60
61			0					61

LINE NO	ITEM	ALLOC	MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	0 FERC	TOTAL COMPANY	LINE NO
1	OPERATING REVENUES							1
2	SALES OF ELECTRICITY		207,731,002	122,589,268	29,544,870	0	359,865,140	2
3	OTHER OPERATING REVENUE		11,550,253	9,712,037	2,267,928	34,702,327	58,232,545	3
4								4
5	TOTAL OPERATING REVENUE		219,281,255	132,301,305	31,812,798	34,702,327	418,097,684	5
6								6
7								7
8	OPERATING EXPENSES							8
9	PRODUCTION EXPENSES		84,805,995	58,417,943	14,076,376	119,209	157,419,523	9
10	TRANSMISSION EXPENSES		15,229,644	11,026,754	2,571,537	219,345	29,047,280	10
11	DISTRIBUTION EXPENSES		7,582,399	7,680,921	1,621,012	33,052	16,917,384	11
12	CUSTOMER ACCOUNTING EXPENSES		6,543,844	6,091,579	1,214,260	242	13,849,926	12
13	CUSTOMER SERVICE AND INFORMATION EXPENSES		8,996,725	1,382,509	718,505	0	11,097,740	13
14	SALES EXPENSES		242,961	22,472	8,194	0	273,627	14
15	ADMINISTRATIVE AND GENERAL EXPENSES		23,663,383	19,282,795	4,364,417	1,969,092	49,279,686	15
16	CHARITABLE CONTRIBUTIONS		0	0	0	0	0	16
17	DEPRECIATION EXPENSE		16,261,713	13,387,642	3,081,270	2,286,099	35,016,724	17
18	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	0	0	18
19	SPIRITWOOD AMORTIZATION		0	0	0	0	0	19
20	GENERAL TAXES		4,666,760	3,936,734	907,387	3,572,002	13,082,883	20
21								21
22	TOTAL OPERATING EXPENSES		167,993,425	121,229,349	28,562,958	8,199,040	325,984,772	22
23								23
24								24
25	NET OPERATING INCOME BEFORE INCOME TAXES		51,287,830	11,071,955	3,249,840	26,503,286	92,112,912	25
26								26
27								27
28	INCOME TAX EXPENSE							28
29	INVESTMENT TAX CREDIT		(1,431,884)	(1,183,682)	(273,754)	(291,189)	(3,180,509)	29
30	DEFERRED INCOME TAXES		(2,553,067)	(1,639,469)	(691,528)	(980,875)	(5,866,242)	30
31	INCOME TAXES		13,309,213	2,408,838	671,032	6,652,118	23,041,293	31
32								32
33	TOTAL INCOME TAX EXPENSE		9,324,262	(414,313)	(294,250)	5,380,054	13,994,542	33
34								34
35								35
36								36
37	NET OPERATING INCOME		41,963,568	11,486,268	3,544,090	21,123,233	78,118,369	37
38								38
39								39
40	Allowance for Funds Used During Construction		1,056,360	0	0	5,146	2,027,574	40
41	Allowance for Funds Used During Construction - MN Only		0	0	0	0	0	41
42	Allowance for Funds Used During Construction - SD Only		0	0	0	0	0	42
43	TOTAL ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION		1,056,360	0	0	5,146	2,027,574	43
44								44
45								45
46	TOTAL AVAILABLE FOR RETURN		43,019,929	11,486,268	3,544,090	21,128,379	80,145,944	46
47								47
48								48
49								49
50								50
51	AVERAGE CENTS PER KWH						***	51
52								52
53								53
54								54
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62								62
63								63

*** NOTE: TOTAL AVAILABLE FOR RETURN WILL NOT ADD ACROSS BECAUSE AFDC IS NOT ALLOCATED TO ALL JURISDICTIONS.

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

LINE NO.	ITEM	AMOUNT	A PERCENT OF TOTAL	COST OF CAPITAL	RATE OF RETURN	LINE NO.
1	CAPITAL STRUCTURE - RATE OF RETURN					1
2						2
3						3
4	LONG-TERM DEBT	510,697,554	47.50%	5.38%	2.55%	4
5	PREFERRED STOCK	0	0.00%	0.00%	0.00%	5
6	COMMON EQUITY	564,383,902	52.50%	22.07%	11.59%	6
7						7
8						8
9						9
10						10
11	TOTAL	1,075,081,457	100.00%		14.14%	11
12						12
13						13
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18						18
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