

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-17-398
OAH File No. 20170622

Exhibit____

RATE DESIGN

Supplemental Direct Testimony and Schedules of

DAVID G. PRAZAK

March 23, 2018

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ATTACHED SCHEDULES

Schedule 1 – OTP Response to ND-PSC-01.21

Schedule 2 – OTP Response to ND-MLEC-120

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

3 A. My name is David G. Prazak. I am employed by Otter Tail Power Company (OTP or
4 Company) as its Supervisor of Pricing and Tariff Administration.

5

6 Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

7 A. Yes. I filed Direct Testimony on behalf of OTP addressing the Company's proposed rate
8 design.

9

10 Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

11 A. The purpose of my Supplemental Direct Testimony is to correct the marginal customer-
12 related costs for the Residential class and our resulting recommended Residential class
13 customer charge. I also present a correction to the Large General Service (LGS) intra-
14 class revenue allocation.

15 **II. PROPOSED RESIDENTIAL CUSTOMER CHARGE**

16 Q. WHAT IS OTP'S PROPOSAL REGARDING FIXED CHARGES IN THIS CASE?

17 A. As noted on page 14 of my Direct Testimony, we recommend bringing customer charges
18 for all classes into better alignment with marginal costs.

19

20 Q. WHAT IS THE MARGINAL CUSTOMER-RELATED COST FOR THE
21 RESIDENTIAL CLASS?

22 A. Table A.2.6 of OTP's 2018 Marginal Cost Study, which was included as Schedule 2 to
23 my Direct Testimony, identifies the marginal customer-related cost for the Residential
24 class to be \$182.78 per year, which translates to \$15.23 per month. Table 4 and Schedule
25 5 of my Direct Testimony incorrectly identified the marginal customer-related cost for
26 the Residential class to be \$17.70 per month. This issue was identified in OTP's response
27 to ND-PSC-01.21, included as Exhibit ___(DGP-2), Schedule 1.

28

1 Q. DOES THIS CHANGE OTP'S PROPOSED CUSTOMER CHARGE FOR THE
2 RESIDENTIAL CLASS?

3 A. Yes. As discussed on pages 13-23 of my Direct Testimony and in our response to Data
4 Request ND-PSC-01.21, it was and is our intent to set the Residential customer charge at
5 100% of marginal customer-related costs. The correct marginal customer-related costs
6 are \$15.23 per month and we recommend the Residential customer charge be set at
7 \$15.23 per month. Making this correction alters the proposed intra-Residential class
8 revenue allocation and rate elements. The proposed intra-Residential class revenue
9 allocation was shown in Attachments 2 and 3 to OTP's response to ND-MLEC-120,
10 which is included as Exhibit ___(DGP-2), Schedule 2. The associated proposed rate
11 elements for the Residential class are shown in Attachment 4 to OTP's response to ND-
12 MLEC-120. The Attachments to ND-MLEC-120 are prepared based on the present and
13 proposed revenue levels from our Initial Filing. The correction to the Residential
14 customer charge will be carried through to the final intra-class revenue allocation and rate
15 elements.

16 **III. LGS INTRA-CLASS REVENUE ALLOCATION**

17 Q. HOW DOES OTP ALLOCATE CLASS REVENUE RESPONSIBILITIES ACROSS
18 RATE CLASSES?

19 A. We allocate class revenue responsibilities to rate classes using the equal percentage of
20 marginal cost (EPMC) methodology. I discussed this process on pages 7-11 of my Direct
21 Testimony.

22
23 Q. IS OTP PROPOSING A CORRECTION TO THE LGS INTRA-CLASS REVENUE
24 ALLOCATION?

25 A. Yes. In preparing our response to ND-MLEC-120, we identified an error in the
26 calculation of the EPMC factors used to calculate the LGS intra-class revenue allocation.
27 Our response ND-MLEC-120 is included as Exhibit ___(DGP-2), Schedule 2. The
28 corrected LGS intra-class revenue allocation and associated LGS class rate elements are
29 shown in Attachments 2-4 of our response to ND-MLEC-120. The Attachments to ND-
30 MLEC-120 are prepared based on the present and proposed revenue levels from our

1 Initial Filing. The correction discussed in ND-MLEC-120 will be carried through to the
2 final intra-class revenue allocation and rate elements.

3 **IV. CONCLUSION**

4 Q. WHAT ARE YOUR CONCLUSIONS?

5 A. The correct marginal customer-related costs are \$15.23 per month and we recommend the
6 Residential Customer charge be set \$15.23 per month. Further, the corrected LGS intra-
7 class revenue allocation and rate elements are shown in Schedule 2.

8

9 Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

10 A. Yes.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Sara Cardwell
Date Received: 11/29/2017
Date Due: 12/13/2017
Date of Response: 12/12/2017
Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Why would Farm Service – Single Phase and Farm Service – Three Phase have a lower proposed customer charge than residential customers? Is this a strict application of cost of service study results versus common sense? Are these customers using less of the system than residential customers? In particular, wouldn't a three phase farm service customer have higher transformer, metering and service costs than a residential customer?

Attachments: 0

Response:

Upon further investigation, the customer charge for Residential 9.01 customers is indeed lower than Farm 9.03 customers. Below is a summary graphic that shows the monthly customer charges for the residential rate classes and farm. For Marginal Cost Study support, see Prazak Direct, Schedule 2, p. 27 and 37 of 43.

		Marginal Customer- Related Cost/mo.
	Residential	
9.01	Residential	15.23
9.02	Residential Controlled Demand	20.18
	Commercial and Industrial	
9.03	Farm Service	17.42

It's important to note the difference between customer charges and distribution facility charges. Marginal customer-related costs include both investment and O&M costs – such as meter and service costs, and customer accounts and customer expenses. In contrast, transformers, secondary lines, and a portion of primary taps are defined as local distribution facilities and are

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Response to Data Request ND-PSC-01.21
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charged under a facilities charge. So, when comparing customer charges among the various rate classes, it is possible to have customer charges within a few dollars – especially when they have similar costs components.

When comparing the distribution facility cost between Residential and Farm, the marginal cost study results indicate farm customers have greater facility costs than residential customers. Farm customers are charged a facility charge, differentiated by single and three-phase customers. These costs are partially recovered through the facility charges. Any remaining facility costs are recovered through the energy charge.

Due to the results as described in this data response, OTP will submit a revision to the Residential 9.01 schedule and impacted areas, after discussions with the North Dakota Staff. The revision will reflect the correct marginal customer charge of \$15.23/month versus the proposed customer charge in Prazak's Direct pp 23 & 24.

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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/23/2018
Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Regarding the intraclass allocation to the LGS class, please provide the calculations of utilizing EPMC method in excel spreadsheet format and also provide a narrative explanation.

Attachments: 4

Attachment 1 to DR ND-MLEC-120.xlsx
Attachment 2 to DR ND-MLEC-120.pdf
Attachment 3 to DR ND-MLEC-120.pdf
Attachment 4 to DR ND-MLEC-120.pdf

Response:

The EPMC methodology allocates the class revenue responsibilities to rate classes based on each rate class's marginal cost revenues. Marginal cost revenues for a rate class are determined by multiplying the marginal cost (modified as discussed above) times the rate class billing determinants. The background supporting the calculation methodology can be found in Mr. Prazak's Direct Testimony, pages 8 through 10.

The calculations, utilizing EPMC method in excel spreadsheet format, are provided in Attachment 1 to ND-MLEC-120. This attachment reflects a correction to an error in Mr. Prazak's original EPMC allocation within the LGS class, which also impacts the rate design levels for all rates in the LGS class. No change occurred for the proposed LGS Class base rate revenues (excluding riders).

There are five basic steps to develop the proposed change for the LGS Class and its associated rates, as shown in Attachment 1 to ND-MLEC-120, and described below:

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Line 1: Change in Non-Fuel Base Revenues. Prazak Direct, Schedule 4, Change in Non-Fuel Base Revenues for LGS Class.

Step 1: Lines 3-8: A table containing 2018 Present Base Rate Revenue (with base fuel but excluding Riders). Prazak Direct, Schedule 4.

Step 2: Lines 9-14: A table containing 2018 Proposed Base Rate Revenue (excluding base fuel and Riders). Prazak Direct, Schedule 4.

Step 3: Lines 15-20: A table containing marginal revenues for the LGS Class. Column G describes the rate efficiency level of the individual rate classes.

Step 4: Lines 21-27: Presents a table of pure EPMC allocation for LGS Class (see Prazak Direct, pp. 8-10)

Step 5: Line 28-34: Presents results of the proposed change for the LGS Class using Method 2a.

EPMC Method 2a was added to correct the error in our original proposed rate design. This new method follows the same concept as Method 2 but makes special adjustments to a couple of rate classes. Method 1 is used for the top two efficient rates - Standby & LGS Primary. LGS TOD is a special case because it contains only one customer in its class. The rate design for the LGS TOD class was designed to be revenue neutral to the LGS NON-TOD Primary and Secondary rate classes. The final revenue requirement for LGS TOD was developed by the revenue it would produce under the revenue-neutral rates. And finally, the LGS Secondary rate revenue allocation was the remainder to achieve the total revenue requirement.

Finally, OTP is providing the following Attachments reflecting the correction discussed above:

- Attachment 2 to DR ND-MLEC-120 – Revised Exhibit____(DGP-1), Schedule 3¹
- Attachment 3 to DR ND-MLEC-120 – Revised Exhibit____(DGP-1), Schedule 4²
- Attachment 4 to DR ND-MLEC-120 – Revised LGS Class Rate Elements.

Attachments 1-4 are prepared based on the present and proposed revenue levels from our Initial Filing. The correction to the LGS rate design shown above and in Attachments 1-4 will be carried through to the final intra-class revenue allocation and rate elements.

¹ Reflects correction to proposed Residential customer charges discussed in ND-PSC-01.21.

² Reflects correction to proposed Residential customer charges discussed in ND-PSC-01.21.

LINE No	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	% Change in Non-Fuel Base Revenues w/Riders	-17%		ND LGS RATES			
2							
3	2018 Present Base Rate Revenue WITH BASE FUEL						
4		Standby Rate	\$	13,134		0.04%	
5	Step 1	RTP Rider	\$	1,245,401	n/a		
6		LGS Secondary	\$	27,517,756		76.13%	
7		LGS Primary	\$	8,579,214		23.74%	
8		LGS Reversal LGS TOD	\$	34,024		0.09%	
9			\$	37,389,529		\$36,144,128	
10	2018 Proposed Base Rate Revenue WITHOUT BASE FUEL						
11	Step 2	Standby Rate	\$	10,824			
12		RTP Rider	\$	1,245,401			
13		LGS Secondary	\$	22,677,157			
14		LGS Primary	\$	7,070,060			
15		LGS TOD	\$	28,039			
16			\$	31,031,481		\$29,786,080	
17							Efficiency Description
18	MARGINAL REVENUES	Standby Rate	\$	11,526		0.03%	94% Most Efficient 1
19	Step 3	RTP Rider	\$		n/a		
20		LGS Secondary	\$	27,358,886		77.31%	83% Less Efficient 3
21		LGS Primary	\$	7,983,245		22.56%	89% More Efficient 2
22		LGS TOD	\$	36,495		0.10%	77% Least Efficient 4
23			\$	35,390,152			
24	Pure EPMC Allocation Method						
25	Step 4	Standby Rate	\$	9,701		-26%	
26		RTP Rider	\$	1,245,401		0%	
27		LGS Secondary	\$	23,026,574		-16%	
28		LGS Primary	\$	6,719,089		-22%	
29		LGS TOD	\$	30,716		-10%	
30			\$	31,031,481			
31	EPMC Allocation Method 2a						
32	Step 5	Standby Rate	\$	10,301		-22%	
33		RTP Rider	\$	1,245,401		0%	
34		LGS Secondary	\$	22,824,720		-17%	
		LGS Primary	\$	6,919,708		-19%	
		LGS TOD	\$	\$31,351.00		-8%	
			\$	31,031,481			

Proposed Test Year 2018 Operating Revenue Summary Comparison - By Rate Schedule

Supplemental Filing

Direct Testimony

Line No.	Rate Schedule	Operating Revenues		Difference	Percent Change
		Present	Proposed		
1	9.01 Residential Service (Rate 101)	\$ 41,898,051	\$ 46,960,808	\$ 5,062,757	12.08%
2	9.02 Residential Demand Control (Rate 241)	\$ 6,311,866	\$ 7,853,867	\$ 1,542,001	24.43%
3					
4	Total Residential:	\$ 48,209,916	\$ 54,814,675	\$ 6,604,759	13.70%
5	9.03 Farm Service (Rate 361)	\$ 2,612,687	\$ 2,970,625	\$ 357,938	13.70%
6					
7	Total Farm:	\$ 2,612,687	\$ 2,970,625	\$ 357,938	13.70%
8	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	\$ 9,525,909	\$ 10,315,886	\$ 789,977	8.29%
9	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	\$ 532	\$ 580	\$ 48	8.96%
10	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	\$ 29,345,494	\$ 31,774,386	\$ 2,428,892	8.28%
11	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	\$ 69,010	\$ 70,401	\$ 1,391	2.02%
12	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)	\$ 9,671	\$ 11,268	\$ 1,597	16.52%
13					
14	Total General Service:	\$ 38,950,615	\$ 42,172,520	\$ 3,221,905	8.27%
15	10.04 Large General Service - Secondary Service (Rate 603)	\$ 31,657,902	\$ 33,871,743	\$ 2,213,842	6.99%
16	10.04 Large General Service - Primary Service (Rate 602) with RTP Rider (Rate 662)	\$ 11,449,285	\$ 12,796,871	\$ 1,347,586	11.77%
17	10.04 Large General Service - Transmission Service (Rate 632)	\$ -	\$ -	\$ -	0.00%
18	10.05 Large General Service Time of Day - Secondary Service (Rates 611, 615, 613)	\$ 38,758	\$ 43,205	\$ 4,447	11.47%
19	10.05 Large General Service Time of Day - Primary Service (Rates 610, 614, 612)	\$ -	\$ -	\$ -	0.00%
20	10.05 Large General Service Time of Day - Transmission Service (Rates 639, 637, 640)	\$ -	\$ -	\$ -	0.00%
21	11.01 Standby Service Rider	\$ 14,765	\$ 13,966	\$ (799)	-5.41%
22					
23	Total Large General Service:	\$ 43,160,710	\$ 46,725,785	\$ 3,565,075	8.26%
24	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)	\$ 27,950	\$ 31,103	\$ 3,153	11.28%
25	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)	\$ 31,131	\$ 39,203	\$ 8,073	25.93%
26					
27	Total Irrigation:	\$ 59,081	\$ 70,307	\$ 11,226	19.00%
28	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)	\$ 97,912	\$ 119,790	\$ 21,878	22.34%
29	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)	\$ 248,383	\$ 320,152	\$ 71,769	28.89%
30	11.03 Outdoor Lighting - Signal (Rate 744)	\$ 37,481	\$ 47,143	\$ 9,662	25.78%
31	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)	\$ 1,900,540	\$ 2,103,818	\$ 203,278	10.70%
32	11.04 Outdoor Lighting - Flood Lighting (Rate 743)	\$ 584,826	\$ 651,228	\$ 66,402	11.35%
33					
34	Total Lighting:	\$ 2,869,142	\$ 3,242,131	\$ 372,989	13.00%
35	11.05 Municipal Pumping - Secondary Service (Rate 872)	\$ 1,200,018	\$ 1,357,078	\$ 157,060	13.09%
36	11.06 Civil Defense - Fire Sirens (Rate 843)	\$ 3,969	\$ 3,426	\$ (542)	-13.66%
37					
38	Total Other Public Authority:	\$ 1,203,986	\$ 1,360,505	\$ 156,519	13.00%
39	14.01 Water Heating - Controlled Service (Rate 191)	\$ 1,085,033	\$ 1,233,682	\$ 148,650	13.70%
40					
41	Total Water Heating:	\$ 1,085,033	\$ 1,233,682	\$ 148,650	13.70%
42	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	\$ 2,480,828	\$ 2,974,204	\$ 493,377	11.83%
43	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	\$ 5,916,326	\$ 6,573,361	\$ 657,034	11.11%
44					
45	Total Interruptible:	\$ 8,397,155	\$ 9,547,565	\$ 1,150,411	13.70%
46	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	\$ 1,036,142	\$ 1,064,957	\$ 28,815	2.78%
47	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	\$ 281,954	\$ 336,896	\$ 54,942	19.49%
48	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	\$ 205,527	\$ 247,622	\$ 42,094	20.48%
49					
50	Total Deferred Load:	\$ 1,523,624	\$ 1,649,475	\$ 125,851	8.26%
51					
52	TOTAL REVENUE:	\$ 148,071,950	\$ 163,787,270	\$ 15,715,320	10.61%

Operating Revenues		Difference	Percent Change
Present	Proposed		
\$ 41,898,051	\$ 47,011,619	\$ 5,113,568	12.20%
\$ 6,311,866	\$ 7,803,055	\$ 1,491,189	23.63%
\$ 48,209,916	\$ 54,814,675	\$ 6,604,759	13.70%
\$ 2,612,687	\$ 2,970,625	\$ 357,938	13.70%
\$ 2,612,687	\$ 2,970,625	\$ 357,938	13.70%
\$ 9,525,909	\$ 10,315,886	\$ 789,977	8.29%
\$ 532	\$ 580	\$ 48	8.96%
\$ 29,345,494	\$ 31,774,386	\$ 2,428,892	8.28%
\$ 69,010	\$ 70,401	\$ 1,391	2.02%
\$ 9,671	\$ 11,268	\$ 1,597	16.52%
\$ 38,950,615	\$ 42,172,520	\$ 3,221,905	8.27%
\$ 31,657,902	\$ 33,821,005	\$ 2,163,104	6.83%
\$ 11,449,285	\$ 12,844,033	\$ 1,394,749	12.18%
\$ -	\$ -	\$ -	0.00%
\$ 38,758	\$ 43,947	\$ 5,189	13.39%
\$ -	\$ -	\$ -	0.00%
\$ -	\$ -	\$ -	0.00%
\$ 14,765	\$ 16,799	\$ 2,034	13.78%
\$ 43,160,710	\$ 46,725,785	\$ 3,565,075	8.26%
\$ 27,950	\$ 31,103	\$ 3,153	11.28%
\$ 31,131	\$ 39,203	\$ 8,073	25.93%
\$ 59,081	\$ 70,307	\$ 11,226	19.00%
\$ 97,912	\$ 119,790	\$ 21,878	22.34%
\$ 248,383	\$ 320,152	\$ 71,769	28.89%
\$ 37,481	\$ 47,143	\$ 9,662	25.78%
\$ 1,900,540	\$ 2,103,818	\$ 203,278	10.70%
\$ 584,826	\$ 651,228	\$ 66,402	11.35%
\$ 2,869,142	\$ 3,242,131	\$ 372,989	13.00%
\$ 1,200,018	\$ 1,357,078	\$ 157,060	13.09%
\$ 3,969	\$ 3,426	\$ (542)	-13.66%
\$ 1,203,986	\$ 1,360,505	\$ 156,519	13.00%
\$ 1,085,033	\$ 1,233,682	\$ 148,650	13.70%
\$ 1,085,033	\$ 1,233,682	\$ 148,650	13.70%
\$ 2,480,828	\$ 2,974,204	\$ 493,377	11.83%
\$ 5,916,326	\$ 6,573,361	\$ 657,034	11.11%
\$ 8,397,155	\$ 9,547,565	\$ 1,150,411	13.70%
\$ 1,036,142	\$ 1,064,957	\$ 28,815	2.78%
\$ 281,954	\$ 336,896	\$ 54,942	19.49%
\$ 205,527	\$ 247,622	\$ 42,094	20.48%
\$ 1,523,624	\$ 1,649,475	\$ 125,851	8.26%
\$ 148,071,950	\$ 163,787,270	\$ 15,715,320	10.61%

CCOSS or EPMC Method	Rate Classes	Proposed Intra-Class Increase	Total Present Revenues (including Riders)	Total Proposed Revenues (including Riders)	Change in Non-Fuel Base Revenues	Present Base Rate Revenue 2018 (excluding Riders)	Proposed Base Rate Revenue (excluding Riders)	2018 Average Revenue 100% Marginal Cost	2018 Proposed Revenue as % of 100% MC	Marginal Revenue Allocation
Method 2	Residential Service	12.08%	\$ 41,898,051	\$ 46,960,808	-1.70%	\$ 36,601,009	\$ 35,979,597	\$ 35,298,607	101.9%	84.9%
	Res. Demand Control	24.43%	\$ 6,311,866	\$ 7,853,867	4.44%	\$ 5,364,879	\$ 5,603,066	\$ 6,271,651	89.3%	15.1%
	RESIDENTIAL CLASS	13.70%	\$ 48,209,916	\$ 54,814,675	-0.91%	\$ 41,965,888	\$ 41,582,663	\$ 41,570,258	100.0%	100.0%
CCOSS	Farm Service	13.70%	\$ 2,612,687	\$ 2,970,625	-2.08%	\$ 2,155,303	\$ 2,110,506	\$ 2,324,518	90.8%	
Method 2	Small General Service	8.29%	\$ 9,526,441	\$ 10,316,466	-4.67%	\$ 8,376,479	\$ 7,985,135	\$ 6,809,680	117.3%	27.7%
	General Service	8.26%	\$ 29,414,504	\$ 31,844,787	-8.25%	\$ 25,575,200	\$ 23,464,413	\$ 17,754,659	132.2%	72.3%
	GS Time of Use	16.52%	\$ 9,671	\$ 11,268	-1.75%	\$ 8,328	\$ 8,182	\$ 7,807	104.8%	0.032%
	GENERAL SERVICE CLASS	8.27%	\$ 38,950,615	\$ 42,172,520	-7.37%	\$ 33,960,007	\$ 31,457,729	\$ 24,572,147	128.0%	100.0%
Method 2a	LGS CLASS	8.26%	\$ 43,160,710	\$ 46,725,785	-17.00%	\$ 37,389,529	\$ 31,031,481	\$ 36,590,771	84.8%	100.0%
	LGS Secondary	6.99%	\$ 31,657,902	\$ 33,871,743	-17.05%	\$ 27,517,756	\$ 22,824,720	\$ 27,358,886	83.4%	74.8%
	LGS Primary & RTP Rider	11.77%	\$ 11,449,285	\$ 12,796,871	-16.89%	\$ 9,824,615	\$ 8,165,110	\$ 9,195,390	88.8%	25.1%
	LGS Transmission	n/a	\$ -	\$ -	n/a	\$ -	\$ -	\$ -	0.0%	0.0%
	LGS Subtotal	8.26%	\$ 43,107,186	\$ 46,668,615	-17.01%	\$ 37,342,371	\$ 30,989,830	\$ 36,554,276	84.8%	99.90%
	LGS TOD Secondary	11.47%	\$ 38,758	\$ 43,205	-7.86%	\$ 34,024	\$ 31,351	\$ 36,495	85.9%	0.1%
	LGS TOD Primary	n/a	\$ -	\$ -	n/a	\$ -	\$ -	\$ -	0.0%	0.0%
	LGS TOD Transmission	n/a	\$ -	\$ -	n/a	\$ -	\$ -	\$ -	0.0%	0.0%
	Standby Service	-5.41%	\$ 14,765	\$ 13,966	-21.57%	\$ 13,134	\$ 10,301	\$ -	0%	0%
	LGS TOD Subtotal	6.8%	\$ 53,523	\$ 57,171	-11.7%	\$ 47,158	\$ 41,652	\$ 36,495	114.1%	0.10%
Method 1	Irrigation	11.28%	\$ 27,950	\$ 31,103	-9.43%	\$ 26,344	\$ 23,859	\$ 25,462	93.7%	47.1%
	Irrigation Time of Use	25.93%	\$ 31,131	\$ 39,203	-9.19%	\$ 29,401	\$ 26,698	\$ 28,569	93.5%	52.9%
	IRRIGATION CLASS	19.0%	\$ 59,081	\$ 70,307	-9.3%	\$ 55,745	\$ 50,557	\$ 54,031	93.6%	100.00%
Method 3	Lighting Energy Only	26.92%	\$ 383,776	\$ 487,085	5.28%	\$ 339,322	\$ 357,222	\$ 148,674	240.3%	21.6%
	Area Lighting	10.85%	\$ 2,485,366	\$ 2,755,046	1.43%	\$ 2,258,606	\$ 2,290,951	\$ 540,068	424.2%	78.4%
	OUTDOOR LIGHTING CLASS	13.00%	\$ 2,869,143	\$ 3,242,131	1.93%	\$ 2,597,928	\$ 2,648,173	\$ 688,742	384.5%	100.00%
CCOSS	Municipal Pumping	13.09%	\$ 1,200,018	\$ 1,357,078	-10.73%	\$ 1,039,969	\$ 928,426	\$ 978,639	94.9%	99.8%
	Fire Sirens	-13.66%	\$ 3,969	\$ 3,426	-8.06%	\$ 3,727	\$ 3,426	\$ 2,423	141.4%	0.2%
	OPA CLASS	13.00%	\$ 1,203,986	\$ 1,360,504	-10.72%	\$ 1,043,696	\$ 931,853	\$ 981,062	95.0%	100.00%
CCOSS	Water Heating	13.70%	\$ 1,085,033	\$ 1,233,682	-13.09%	\$ 987,779	\$ 858,515	\$ 1,319,964	65.0%	100.0%
Method 1	Large Dual Fuel	19.89%	\$ 2,480,828	\$ 2,974,204	-40.80%	\$ 2,130,188	\$ 1,261,089	\$ 2,819,159	44.7%	27.1%
	Small Dual Fuel	11.11%	\$ 5,916,326	\$ 6,573,361	-37.59%	\$ 5,165,773	\$ 3,223,769	\$ 7,600,519	42.4%	72.9%
	CONTROLLED SERVICE INTERRUPTIBLE	11.5%	\$ 8,397,155	\$ 9,547,565	11.5%	\$ 7,295,962	\$ 4,484,858	\$ 10,419,677	43.0%	100.00%
Method 1	Deferred Load	2.78%	\$ 1,036,142.38	\$ 1,064,957.03	-32.02%	\$ 918,394	\$ 624,307	\$ 806,358	77.4%	71.5%
	Fixed Time of Service	19.91%	\$ 487,482	\$ 584,518	-34.07%	\$ 242,868	\$ 160,130	\$ 321,682	49.8%	28.5%
	CONTROLLED SERVICE DEFERRED	8.26%	\$ 1,523,624	\$ 1,649,475	-32.83%	\$ 1,337,726	\$ 898,580	\$ 1,128,041	79.7%	100.00%
	Total	10.61%	\$ 148,071,950	\$ 163,787,269	-9.89%	\$ 128,789,562	\$ 116,054,915	\$ 82,406,193	140.8%	

Line No.	Charge	Units	Present Rate		Proposed (Initial Filing) Rate		Proposed (Revised) Rate	
			Summer	Winter	Summer	Winter	Summer	Winter
225								
226	10.05 Large General Service Time of Day - Primary Service (Rates 610, 614, 612)							
227	Customer Charge	Bills	\$60.00	\$60.00	\$282.00	\$282.00	\$282.00	\$282.00
228	Facilities Charge - All kW	kW	\$0.11	\$0.11	\$0.48	\$0.48	\$0.48	\$0.48
229	Energy - On-Peak	kWh	\$0.08115	\$0.07278	\$0.04529	\$0.03945	\$0.04456	\$0.03882
230	Energy - Shoulder	kWh	\$0.06221	\$0.05921	\$0.03457	\$0.03527	\$0.03402	\$0.03470
231	Energy - Off-Peak	kWh	\$0.03709	\$0.04184	\$0.02300	\$0.02475	\$0.02250	\$0.02436
232	Demand per kW - On-Peak	kW	\$5.71	\$4.39	\$7.56	\$3.42	\$7.77	\$5.03
233	Demand per kW - Shoulder	kW	\$1.57	\$1.21	\$3.36	\$2.53	\$3.29	\$3.24
234	Demand per kW - Off-Peak	kW	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
243								
244	10.05 Large General Service Time of Day - Transmission Service (Rates 639, 637, 640)							
245	Customer Charge	Bills	\$60.00	\$60.00	\$282.00	\$282.00	\$282.00	\$282.00
246	Facilities Charge	kW	N/A	N/A	N/A	N/A	N/A	N/A
247	Energy - On-Peak	kWh	\$0.07900	\$0.07063	\$0.03853	\$0.03328	\$0.04184	\$0.03613
248	Energy - Shoulder	kWh	\$0.06066	\$0.05752	\$0.02956	\$0.02991	\$0.03210	\$0.03247
249	Energy - Off-Peak	kWh	\$0.03635	\$0.04070	\$0.02798	\$0.02980	\$0.02140	\$0.02292
250	Demand per kW - On-Peak	kW	\$4.86	\$3.74	\$5.52	\$3.17	\$5.52	\$3.97
251	Demand per kW - Shoulder	kW	\$1.06	\$0.82	\$2.74	\$2.48	\$2.74	\$2.68
252	Demand per kW - Off-Peak	kW	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
266								
267	11.01 Standby Service - Option A: Firm - Secondary Service (Rates 947, 948, 949)							
268	Customer Charge	Bills	\$199.00	\$199.00	\$242.24	\$242.24	\$242.24	\$242.24
269	Facilities Charge per month per kW of Contracted Backup	kW	\$0.30	\$0.30	\$0.55	\$0.55	\$0.55	\$0.55
270	Reservation Charge per kW of Contracted Backup	kW	\$0.85069	\$0.09697	\$0.65645	\$0.22355	\$0.65645	\$0.22355
271	Metered Demand per day per kW On-Peak Backup	kW	\$0.49076	\$0.32187	\$0.54794	\$0.43005	\$0.54794	\$0.43005
272	Energy - On-Peak	kWh	\$0.08150	\$0.07314	\$0.05596	\$0.04903	\$0.04485	\$0.03929
273	Energy - Shoulder	kWh	\$0.06247	\$0.05949	\$0.04257	\$0.04368	\$0.03412	\$0.03500
274	Energy - Off-Peak	kWh	\$0.03721	\$0.04199	\$0.02818	\$0.03054	\$0.02258	\$0.02448
275								
277	11.01 Standby Service - Option A: Firm - Primary Service (Rates 944, 945, 946)							
278	Customer Charge	Bills	\$199.00	\$199.00	\$304.33	\$304.33	\$304.33	\$304.33
279	Facilities Charge per month per kW of Backup	kW	\$0.11	\$0.11	\$0.45	\$0.45	\$0.45	\$0.45
280	Reservation Charge per kW of Contracted Backup	kW	\$0.84590	\$0.09634	\$0.62837	\$0.21403	\$0.62837	\$0.21403
281	Metered Demand per day per kW On-Peak Backup	kW	\$0.48683	\$0.31978	\$0.52464	\$0.40800	\$0.52464	\$0.40800
282	Energy - On-Peak	kWh	\$0.08115	\$0.07278	\$0.04529	\$0.03945	\$0.04456	\$0.03882
283	Energy - Shoulder	kWh	\$0.06221	\$0.05921	\$0.03457	\$0.03527	\$0.03402	\$0.03470
284	Energy - Off-Peak	kWh	\$0.03709	\$0.04181	\$0.02300	\$0.02475	\$0.02250	\$0.02436
286								
287	11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)							
288	Customer Charge	Bills	\$199.00	\$199.00	\$304.33	\$304.33	\$304.33	\$304.33
289	Facilities Charge per month per kW of Backup	kW	N/A	N/A	N/A	N/A	N/A	N/A
290	Reservation Charge per kW of Contracted Backup	kW	\$0.81704	\$0.09254	\$0.58422	\$0.19898	\$0.58422	\$0.19898
291	Metered Demand per day per kW On-Peak Backup	kW	\$0.35865	\$0.28694	\$0.48812	\$0.37420	\$0.48812	\$0.37420
292	Energy - On-Peak	kWh	\$0.07900	\$0.07063	\$0.03853	\$0.03328	\$0.04184	\$0.03613
293	Energy - Shoulder	kWh	\$0.06066	\$0.05752	\$0.02956	\$0.02991	\$0.03210	\$0.03247
294	Energy - Off-Peak	kWh	\$0.03635	\$0.04070	\$0.02798	\$0.02980	\$0.02140	\$0.02292
296								
297	11.01 Standby Service - Option B: Non-Firm - Secondary Service (Rates 956, 957, 958)							
298	Customer Charge	Bills	\$199.00	\$199.00	\$242.24	\$242.24	\$242.24	\$242.24
299	Facilities Charge per month per kW of Backup	kW	\$0.30	\$0.30	\$0.55	\$0.55	\$0.55	\$0.55

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Line No.	Charge	Units	Present Rate		Proposed (Initial Filing) Rate		Proposed (Revised) Rate	
			Summer	Winter	Summer	Winter	Summer	Winter
300	Energy - On-Peak	kWh	N/A	N/A	N/A	N/A	N/A	N/A
301	Energy - Shoulder	kWh	\$0.06247	\$0.05949	\$0.04257	\$0.04368	\$0.03412	\$0.03500
302	Energy - Off-Peak	kWh	\$0.03721	\$0.04199	\$0.02818	\$0.03054	\$0.02258	\$0.02448
304								
305	11.01 Standby Service - Option B: Non-Firm - Primary Service (Rates 953, 954, 955)							
306	Customer Charge	Bills	\$199.00	\$199.00	\$304.33	\$304.33	\$304.33	\$304.33
307	Facilities Charge per month per kW of Backup	kW	\$0.11	\$0.11	\$0.45	\$0.45	\$0.45	\$0.45
308	Energy - On-Peak	kWh	N/A	N/A	N/A	N/A	N/A	N/A
309	Energy - Shoulder	kWh	\$0.06221	\$0.05921	\$0.03457	\$0.03527	\$0.03402	\$0.03470
310	Energy - Off-Peak	kWh	\$0.03709	\$0.04181	\$0.02300	\$0.02475	\$0.02250	\$0.02436
312								
313	11.01 Standby Service - Option B: Non-Firm - Transmission Service (Rates 950, 951, 952)							
314	Customer Charge	Bills	\$199.00	\$199.00	\$304.33	\$304.33	\$304.33	\$304.33
315	Facilities Charge per month per kW of Backup	kW	N/A	N/A	N/A	N/A	N/A	N/A
316	Energy - On-Peak	kWh	N/A	N/A	N/A	N/A	N/A	N/A
317	Energy - Shoulder	kWh	\$0.06066	\$0.05752	\$0.02956	\$0.02991	\$0.03210	\$0.03247
318	Energy - Off-Peak	kWh	\$0.03635	\$0.04070	\$0.02798	\$0.02980	\$0.02140	\$0.02292