Workpaper 25
Smart Metering Statement

Dakota Electric Association

Smart Metering Statement

In an August 10, 2007 Order in Docket Number E-999/CI-06-159, the Commission stated its intention to examine individual utility smart metering practices in the context of rate cases.

On November 20, 2017, Dakota Electric Association (Dakota Electric or Cooperative) submitted a Petition (Docket No. E-111/M-17-821) requesting Minnesota Public Utilities Commission (Commission or MPUC) approval to implement tracker recovery for Advanced Grid Infrastructure (AGi) investments. The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases. This filing included 1) a detailed review of activities that the Cooperative has undertaken in evaluating AGi and 2) business case analysis supporting the implementation of AGi technologies. The Commission approved the AGi Tracker Recovery in a May 8, 2018 Order.

Advanced Grid Infrastructure (AGi) is the term Dakota Electric is using to refer to new technologies that would enhance the communication and operation of our distribution system that delivers electricity to our members. These technologies will help Dakota Electric monitor our distribution system for better efficiency and operation and allow us to have two-way communication to field equipment, providing numerous benefits to our members and Dakota Electric. The main AGi components include Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and the Load Management (LM) system.

Advanced Metering Infrastructure is the foundational component of the Advanced Grid functions. AMI is a system wide communication network for meters and other devices. AMI provides a communication path which can be used to read meters, control loads within the Load Management system, and interface with the SCADA (Supervisory Control And Data Acquisition) system for distribution operations and monitoring.

Meter Data Management provides an organized place to store, retrieve, report and analyze the data collected by the AMI and many other systems. The MDM is a data warehouse and hub, with integration to many of the other Advanced Grid technologies including SCADA, Customer Information System (CIS), Outage Management System (OMS), and Geographic Information System (GIS).

Load Management provides control of consumer loads when required through Load Control Receivers (LCR) mounted to each member building participating in a load management rate. The LCR device is the “switch” at members’ homes and businesses to directly control the load when required. Air conditioners, water heaters, electric heat etc., are remotely turned off by a signal sent to the load control receiver. The load management system provides this capability/functionality to residential, commercial and agricultural loads.

Workpaper 24
Reconciliation

Dakota Electric Association			Billing Units (1)									
			Avg. No. of	Energy					Demand			
Line	Rate	Rate	Consumers	Summer	Other			Total	Summer	Winter	Other	Total
No.	Schedule	Class	(2019 Budget)	(kWh)	(kWh)			(kWh)	(kW)	(kW)	(kW)	(kW)
								=(b+c+d)				=(f+g+h)
			(a)	(b)	(c)	(d)		(e)	(f)	(g)	(h)	(i)
1	31	Residential & Farm Service	100,202	257,025,312	581,064,216			838,089,528				-
2	32	Residential & Farm Demand Control	15	378,000				378,000	182.2		735.0	917.2
	33	Electric Vehicle	88	280,402	8,554	2,693	9,311	300,960				
3	36	Irrigation Service - Firm Rate	8	162,528				162,528	902.3	2.5	962.5	1,867.3
4	36	Irrigation Service - Controlled Rate	384	7,801,344				7,801,344	74,387.5			74,387.5
5	41	Small General Service	4,431	10,541,910	31,995,690			42,537,600				-
6	44	Security Lighting Service		405,600				405,600				
7		175 W MV	-									-
8		100 W HPS	819									-
9		150 W HPS	4									-
10		250 W HPS	8									-
11		**Sub-Total**	831	405,600	-			405,600				-
12	44-2	Street Lighting Service		2,405,280				2,405,280				-
13		175 W MV	-					-				-
14		250 W MV	3					-				-
15		400 W MV	-					-				-
16		100 W HPS	38					-				-
17		150 W HPS	646					-				-
18		250 W HPS	1,597					-				-
19		400 W HPS	1					-				-
20		**Sub-Total**	2,285	2,405,280	-			2,405,280				-
21	44-1	Street Lighting Service		521,040				521,040				-
22		175 W MV	-					-				-
23		250 W MV	-					-				-
24		400 W MV	-					-				-
25		100 W HPS	-					-				-
26		150 W HPS	101					-				-
27		200 W HPS	101					-				-
28		250 W HPS	272					-				-
29		400 W HPS	13					-				-
30		**Sub-Total**	487	521,040	-			521,040				-
31	44-3	Custom Residential Street Lighting		6,750,960				6,750,960				-
32		175 W MV	-					-				-
33		50 W HPS	81					-				-
34		100 W HPS	8,416					-				-
35		150 W HPS	3,732					-				-
36		250 W HPS	4					-				-
37		**Sub-Total**	12,233	6,750,960	-			6,750,960				-
	44-4	LED Security Lighting	338					64,896				-
	44-5	LED Street Lighting Member Owned		8,712				8,712				-
		A	-					-				-
		B	-					-				-
		C	11					-				-
		D	-					-				-
		E	-					-				-
		Sub-Total	11	8,712	-			8,712				-
	44-6	LED Street Lighting		202,152				202,152				-
		Standard Coach Post	121					-				-
		Standard Acorn Post	48					-				-
		Standard Cobra Mast	91					-				-
		Standard Shoebox	151					-				-
		Basic Coach Post	41					-				-
		Basic Acorn Post	-					-				-
		Basic Cobra Mast	53					-				-
		Basic Shoebox	16					-				-
		Sub-Total		202,152	-			202,152				
38	45	Low Wattage Unmetered Service	71					-				-
39	46	General Service	2,750	264,418,387	158,964,779	38,616,837		462,000,003	413,627.7		1,028,872.7	1,442,500.4
40	47	Municipal Civil Defense Sirens	66					-				-
41	49	Geothermal Heat Pump	3	172,800				172,800				
42	51	Controlled Off-peak Energy Storage	1,718									
43		Energy Net Charge--Rate 31		2,701,434	7,509,011			10,210,445				-
44		Energy Charge--Rate 41		6,874	39,232			46,106				-
45		Energy Charge--Rate 46		51,449				51,449				-
46		**Sub-Total**						10,308,000				-
47	52	Interruptible Heating Service	6,686									
48		Energy Net Charge--Rate 31		10,488,495	32,538,130			43,026,625				-
49		Energy Charge--Rate 41		64,095	386,791			450,886				-
50		Energy Charge--Rate 46		650,089				650,089				-
51		**Sub-Total**						44,127,600				-
52	53	Residential & Farm Time of Use	18	49,271	12,117	154,828		216,216				-
53	54	General Service Time of Use	6	1,059,984				1,059,984	960.1	436.9	1,253.2	4,152.1
54	60	Standby Service	1					-	1,000	1,000	1,000	12,000
55	70	Full Interruptible Service	234	379,080,000				379,080,000	1,042.8	-	-	858,880.1
56	71	Partial Interruptible Service	28	27,720,000				27,720,000	3,212.2	2,980.2	5,964.3	111,609.5

Dakota Electric Association			Billing Units (1)									
			Avg. No. of	Energy					Demand			
Line	Rate	Rate	Consumers	Summer	Other			Total	Summer	Winter	Other	Total
No.	Schedule	Class	(2019 Budget)	(kWh)	(kWh)			(kWh)	(kW)	(kW)	(kW)	(kW)
								=(b+c+d)				=(f+g+h)
			(a)	(b)	(c)	(d)		(e)	(f)	(g)	(h)	(i)
57	80	Controlled Air Conditioning Service	39,480									
58		Option 1						-				
59		Option 2										
60		Residential Rate 8131		4,858,654				4,858,654				
61		Rate 8141		216,346				216,346				
62		Rate 8146		-				-				
63		**Sub-Total**						5,075,000				
64		Option 3										
65		Residential Rate 8231	35,158								6,802.30	
66		Commercial	-									
67		**Sub-Total**	35,158									
68		Option 4										
69		Rate 8441	4,699									
70		Rate 8446	-									
71		**Sub-Total**	4,699									
72		Current Cost of Power Adj (Carryover) (9)										
73		Current Cost of Power Adj (Other) (10)										
74		**Wellspring**										
75		**Grand Total**	108,165					1,824,313,203				2,496,964.3
		Check Total	108,165					1,824,313,200				2,496,964.3
		Difference	-					3				-
					Line Loss			2.500%				
					Purchases			1,871,090,000				

Dakota Electric Association			Present Rates (2)										
			Fixed	Energy Charge			Demand Charge			RTA Charge / kWh (3)			
Line	Rate	Rate	Charge	Summer	Winter	Other	Summer	Winter	Other	Power	CIP	Prop	Net
No.	Schedule	Class	per Mo.	per kWh	per kWh	per kWh	per kW	per kW	per kW	Cost Adj	Adj	Tax Adj	RTA
													=(q+r+s)
			(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	31	Residential & Farm Service	$ 9.00	$ 0.1308		$ 0.1168				$ 0.0024	$ 0.0001	$ -	$ 0.0025
2	32	Residential & Farm Demand Control	$ 12.00	$ 0.0760			$ 14.70		$ 11.10	$ 0.0024	$ 0.0001	$ -	$ 0.0025
	33	Electric Vehicle		$ 0.06740	$ 0.41440	$ 0.13080	$ 0.11680			$ 0.0024	$ 0.0001	$ -	$ 0.0025
3	36	Irrigation Service - Firm Rate	$ 30.00	$ 0.0499			$ 26.35	$ 20.96	$ 15.50	$ 0.0024	$ 0.0001	$ -	$ 0.0025
4	36	Irrigation Service - Controlled Rate	$ 30.00	$ 0.0499			$ 4.55			$ (0.0006)	$ 0.0001	$ -	$ (0.0005)
5	41	Small General Service	$ 14.00	$ 0.1269		$ 0.1129				$ 0.0024	$ 0.0001	$ -	$ 0.0025
6	44	Security Lighting Service								$ 0.0024	$ 0.0001	$ -	$ 0.0025
7		175 W MV	$ -							$ 0.0024			
8		100 W HPS	$ 10.10							$ 0.0024			
9		150 W HPS	$ 11.99							$ 0.0024			
10		250 W HPS	$ 15.79							$ 0.0024			
11		**Sub-Total**								$ 0.0024			
12	44-2	Street Lighting Service								$ 0.0024	$ 0.0001	$ -	$ 0.0025
13		175 W MV	$ 15.23							$ 0.0024			$ 0.0024
14		250 W MV	$ 18.16							$ 0.0024			$ 0.0024
15		400 W MV	$ 23.25							$ 0.0024			$ 0.0024
16		100 W HPS	$ 12.27							$ 0.0024			$ 0.0024
17		150 W HPS	$ 14.16							$ 0.0024			$ 0.0024
18		250 W HPS	$ 17.95							$ 0.0024			$ 0.0024
19		400 W HPS	$ 22.38							$ 0.0024			$ 0.0024
20		**Sub-Total**								$ 0.0024			$ 0.0024
21	44-1	Street Lighting Service								$ 0.0024	$ 0.0001	$ -	$ 0.0025
22		175 W MV	$ 10.52							$ 0.0024			$ 0.0024
23		250 W MV	$ 13.46							$ 0.0024			$ 0.0024
24		400 W MV	$ 18.54							$ 0.0024			$ 0.0024
25		100 W HPS	$ 7.56							$ 0.0024			$ 0.0024
26		150 W HPS	$ 9.46							$ 0.0024			$ 0.0024
27		200 W HPS	$ 11.41							$ 0.0024			$ 0.0024
28		250 W HPS	$ 13.25							$ 0.0024			$ 0.0024
29		400 W HPS	$ 17.67							$ 0.0024			$ 0.0024
30		**Sub-Total**								$ 0.0024			$ 0.0024
31	44-3	Custom Residential Street Lighting								$ 0.0024	$ 0.0001	$ -	$ 0.0025
32		175 W MV	$ 11.37							$ 0.0024			
33		50 W HPS	$ 6.70							$ 0.0024			
34		100 W HPS	$ 8.41							$ 0.0024			
35		150 W HPS	$ 10.30							$ 0.0024			
36		250 W HPS	$ 14.09							$ 0.0024			
37		**Sub-Total**								$ 0.0024			$ 0.0024
	44-4	LED Security Lighting	$ 7.63							$ 0.0024	$ 0.0001	$ -	$ 0.0025
	44-5	LED Street Lighting Member Owned								$ 0.0024	$ 0.0001	$ -	$ 0.0025
		A	$ 4.81							$ 0.0024			
		B	$ 6.71							$ 0.0024			
		C	$ 9.66							$ 0.0024			
		D	$ 13.05							$ 0.0024			
		E	$ 16.52							$ 0.0024			
		Sub-Total								$ 0.0024			$ 0.0024
	44-6	LED Street Lighting								$ 0.0024	$ 0.0001	$ -	$ 0.0025
		Standard Coach Post	$ 10.60							$ 0.0024			
		Standard Acorn Post	$ 11.24							$ 0.0024			
		Standard Cobra Mast	$ 8.31							$ 0.0024			
		Standard Shoebox	$ 10.71							$ 0.0024			
		Basic Coach Post	$ 6.83							$ 0.0024			
		Basic Acorn Post	$ 6.30							$ 0.0024			
		Basic Cobra Mast	$ 6.51							$ 0.0024			
		Basic Shoebox	$ 7.98							$ 0.0024			
		Sub-Total											
38	45	Low Wattage Unmetered Service	$ 10.00										$ -
39	46	General Service	$ 34.00	$ 0.07760	$ 0.06760	$ 0.05760	$ 12.26		$ 9.16	$ 0.0024	$ 0.0001	$ -	$ 0.0025
40	47	Municipal Civil Defense Sirens	$ 5.00										$ -
41	49	Geothermal Heat Pump		$ 0.0940						$ 0.0018	$ 0.0001	$ -	$ 0.0019
42	51	Controlled Off-peak Energy Storage											
43		Energy Net Charge--Rate 31		$ 0.0440	$ 0.0440					$ 0.0005	$ 0.0001	$ -	$ 0.0006
44		Energy Charge--Rate 41		$ 0.0440	$ 0.0440					$ 0.0005	$ 0.0001	$ -	$ 0.0006
45		Energy Charge--Rate 46		$ 0.0440	$ 0.0440					$ 0.0005	$ 0.0001	$ -	$ 0.0006
46		**Sub-Total**											
47	52	Interruptible Heating Service											
48		Energy Net Charge--Rate 31		$ 0.0550	$ 0.0550					$ 0.0046	$ 0.0001	$ -	$ 0.0047
49		Energy Charge--Rate 41		$ 0.0550	$ 0.0550					$ 0.0046	$ 0.0001	$ -	$ 0.0047
50		Energy Charge--Rate 46		$ 0.0550	$ 0.0550					$ 0.0046	$ 0.0001	$ -	$ 0.0047
51		**Sub-Total**											
52	53	Residential & Farm Time of Use	$ 12.00	0.18800	0.17400	$ 0.09400				$ 0.0024	$ 0.0001	$ -	$ 0.0025
53	54	General Service Time of Use	$ 36.00	$ 0.0499		$ 4.75	$ 24.85	$ 18.95	$ 13.00	$ 0.0024	$ 0.0001	$ -	$ 0.0025
54	60	Standby Service				$ 3.28	$ 3.21	$ 2.47	$ 1.74				$ -
55	70	Full Interruptible Service	$ 110.00	$ 0.04990	Failure	$ 4.75	$ 24.85	$ 18.95	$ 13.00	$ (0.0006)	$ 0.0001	$ -	$ (0.0005)
56	71	Partial Interruptible Service	$ 110.00	$ 0.04990		$ 4.75	$ 24.85	$ 18.95	$ 13.00	$ (0.0006)	$ 0.0001	$ -	$ (0.0005)

Dakota Electric Association			Present Rates (2)										
			Fixed	Energy Charge			Demand Charge			RTA Charge / kWh (3)			
Line	Rate	Rate	Charge	Summer	Winter	Other	Summer	Winter	Other	Power	CIP	Prop	Net
No.	Schedule	Class	per Mo.	per kWh	per kWh	per kWh	per kW	per kW	per kW	Cost Adj	Adj	Tax Adj	RTA
													=(q+r+s)
			(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
57	80	Controlled Air Conditioning Service											
58		Option 1											$ -
59		Option 2											
60		Residential Rate 8131		$ (0.0320)									$ -
61		Rate 8141		$ (0.0320)									$ -
62		Rate 8146		$ (0.0320)									$ -
63		**Sub-Total**											$ -
64		Option 3											
65		Residential Rate 8231	$ (13.00)										$ -
66		Commercial	$ (13.00)										$ -
67		**Sub-Total**											$ -
68		Option 4											
69		Rate 8441	$ (6.50)										$ -
70		Rate 8446	$ (6.50)										$ -
71		**Sub-Total**											$ -
72		Current Cost of Power Adj (Carryover) (9)											
73		Current Cost of Power Adj (Other) (10)											
74		**Wellspring**											
75		**Grand Total**											
		Check Total											
		Difference											

Dakota Electric Association			Revenue under Present Rates						Cost of Power-Present Rates			
								DEA1 p14-20	Base		Net	
Line	Rate	Rate	Fixed	Energy	Demand	RTA (3)	Other (4)	Total	Cost of	PCA in	Cost of	
No.	Schedule	Class	Charge	Charge	Charge	Charge	Chg/Credits	Revenue	Power	RTA	Power	$
			=(a*j)*12	=(b*k+c*l+d*m)	=(f*n+g*o+h*p)	=(e*t)		(u+v+w+x+y)			=(u+v)	=(e*ac)
			(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)
1	31	Residential & Farm Service	$ 10,821,816	$ 101,487,211	$ -	$ 2,095,224	$ (72,216)	$ 114,332,035	$ 0.0903	$ 0.0024	$ 0.0927	$ 77,690,899
2	32	Residential & Farm Demand Control	$ 2,160	$ 28,728	$ 10,837	$ 945		$ 42,670	$ 0.0903	$ 0.0024	$ 0.0927	$ 35,041
	33	Electric Vehicle	$ -	$ 23,884	$ -	$ 752		$ 24,636	$ 0.0200	$ 0.0005	$ 0.0205	$ 6,170
3	36	Irrigation Service - Firm Rate	$ 2,880	$ 8,110	$ 38,747	$ 406		$ 50,143	$ 0.0903	$ 0.0024	$ 0.0927	$ 15,066
4	36	Irrigation Service - Controlled Rate	$ 138,240	$ 389,287	$ 338,463	$ (3,901)		$ 862,089	$ 0.0497	$ (0.0006)	$ 0.0491	$ 383,046
5	41	Small General Service	$ 744,408	$ 4,950,082	$ -	$ 106,344	$ (1,224)	$ 5,799,610	$ 0.0903	$ 0.0024	$ 0.0927	$ 3,943,236
6	44	Security Lighting Service	$ -	$ -	$ -	$ 1,014		$ 1,014	$ 0.0903	$ 0.0024	$ 0.0927	$ 37,599
7		175 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
8		100 W HPS	$ 99,263	$ -	$ -	$ -		$ 99,263	$ 0.0903	$ 0.0024	$ 0.0927	$ -
9		150 W HPS	$ 576	$ -	$ -	$ -		$ 576	$ 0.0903	$ 0.0024	$ 0.0927	$ -
10		250 W HPS	$ 1,516	$ -	$ -	$ -		$ 1,516	$ 0.0903	$ 0.0024	$ 0.0927	$ -
11		**Sub-Total**	$ 101,355	$ -	$ -	$ 1,014	$ -	$ 102,369	$ 0.0903	$ 0.0024	$ 0.0927	$ 37,599
12	44-2	Street Lighting Service	$ -	$ -	$ -	$ 6,013		$ 6,013	$ 0.0903	$ 0.0024	$ 0.0927	$ 222,969
13		175 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
14		250 W MV	$ 654	$ -	$ -	$ -		$ 654	$ 0.0903	$ 0.0024	$ 0.0927	$ -
15		400 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
16		100 W HPS	$ 5,595	$ -	$ -	$ -		$ 5,595	$ 0.0903	$ 0.0024	$ 0.0927	$ -
17		150 W HPS	$ 109,768	$ -	$ -	$ -		$ 109,768	$ 0.0903	$ 0.0024	$ 0.0927	$ -
18		250 W HPS	$ 343,994	$ -	$ -	$ -		$ 343,994	$ 0.0903	$ 0.0024	$ 0.0927	$ -
19		400 W HPS	$ 269	$ -	$ -	$ -		$ 269	$ 0.0903	$ 0.0024	$ 0.0927	$ -
20		**Sub-Total**	$ 460,280	$ -	$ -	$ 6,013	$ -	$ 466,293	$ 0.0903	$ 0.0024	$ 0.0927	$ 222,969
21	44-1	Street Lighting Service	$ -	$ -	$ -	$ 1,303		$ 1,303	$ 0.0903	$ 0.0024	$ 0.0927	$ 48,300
22		175 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
23		250 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
24		400 W MV	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
25		100 W HPS	$ -	$ -	$ -	$ -		$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
26		150 W HPS	$ 11,466	$ -	$ -	$ -		$ 11,466	$ 0.0903	$ 0.0024	$ 0.0927	$ -
27		200 W HPS	$ 13,829	$ -	$ -	$ -		$ 13,829	$ 0.0903	$ 0.0024	$ 0.0927	$ -
28		250 W HPS	$ 43,248	$ -	$ -	$ -		$ 43,248	$ 0.0903	$ 0.0024	$ 0.0927	$ -
29		400 W HPS	$ 2,757	$ -	$ -	$ -		$ 2,757	$ 0.0903	$ 0.0024	$ 0.0927	$ -
30		**Sub-Total**	$ 71,300	$ -	$ -	$ 1,303	$ -	$ 72,603	$ 0.0903	$ 0.0024	$ 0.0927	$ 48,300
31	44-3	Custom Residential Street Lighting	$ -	$ -	$ -	$ 16,877		$ 16,877	$ 0.0903	$ 0.0024	$ 0.0927	$ 625,814
32		175 W MV	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
33		50 W HPS	$ 6,512	$ -	$ -			$ 6,512	$ 0.0903	$ 0.0024	$ 0.0927	$ -
34		100 W HPS	$ 849,343	$ -	$ -			$ 849,343	$ 0.0903	$ 0.0024	$ 0.0927	$ -
35		150 W HPS	$ 461,275	$ -	$ -			$ 461,275	$ 0.0903	$ 0.0024	$ 0.0927	$ -
36		250 W HPS	$ 676	$ -	$ -			$ 676	$ 0.0903	$ 0.0024	$ 0.0927	$ -
37		**Sub-Total**	$ 1,317,806			$ 16,877		$ 1,334,683	$ 0.0903	$ 0.0024	$ 0.0927	$ 625,814
	44-4	LED Security Lighting	$ 30,947	$ -	$ -	$ 162		$ 31,109	$ 0.0903	$ 0.0024	$ 0.0927	$ 6,016
	44-5	LED Street Lighting Member Owned	$ -	$ -	$ -	$ 22		$ 22	$ 0.0903	$ 0.0024	$ 0.0927	$ 808
		A	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		B	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		C	$ 1,275	$ -	$ -			$ 1,275	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		D	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		E	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Sub-Total	$ 1,275			$ 22		$ 1,297	$ 0.0903	$ 0.0024	$ 0.0927	$ 808
	44-6	LED Street Lighting	$ -	$ -	$ -	$ 505		$ 505	$ 0.0903	$ 0.0024	$ 0.0927	$ 18,739
		Standard Coach Post	$ 15,391	$ -	$ -			$ 15,391	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Standard Acorn Post	$ 6,474	$ -	$ -			$ 6,474	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Standard Cobra Mast	$ 9,075	$ -	$ -			$ 9,075	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Standard Shoebox	$ 19,407	$ -	$ -			$ 19,407	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Basic Coach Post	$ 3,360	$ -	$ -			$ 3,360	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Basic Acorn Post	$ -	$ -	$ -			$ -	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Basic Cobra Mast	$ 4,140	$ -	$ -			$ 4,140	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Basic Shoebox	$ 1,532	$ -	$ -			$ 1,532	$ 0.0903	$ 0.0024	$ 0.0927	$ -
		Sub-Total	59,379	-	-	505	-	59,884				18,739
38	45	Low Wattage Unmetered Service	$ 8,520	$ -	$ -	$ -		$ 8,520				
39	46	General Service	$ 1,122,000	$ 33,489,216	$ 14,495,550	$ 1,155,000	$ -	$ 50,261,766	$ 0.0903	$ 0.0024	$ 0.0927	$ 42,827,400
40	47	Municipal Civil Defense Sirens	$ 3,960	$ -	$ -	$ -		$ 3,960				
41	49	Geothermal Heat Pump		$ 16,243		$ 328		$ 16,571	$ 0.0775	$ 0.0018	$ 0.0793	$ 13,703
42	51	Controlled Off-peak Energy Storage										
43		Energy Net Charge--Rate 31	$ -	$ 449,260	$ -	$ 6,126		$ 455,386	$ 0.0200	$ 0.0005	$ 0.0205	$ 209,314
44		Energy Charge--Rate 41	$ -	$ 2,029	$ -	$ 28		$ 2,057	$ 0.0200	$ 0.0005	$ 0.0205	$ 945
45		Energy Charge--Rate 46	$ -	$ 2,264	$ -	$ 31		$ 2,295	$ 0.0200	$ 0.0005	$ 0.0205	$ 1,055
46		**Sub-Total**	$ -	$ 453,553	$ -	$ 6,185	$ -	$ 459,738				$ 211,314
47	52	Interruptible Heating Service										
48		Energy Net Charge--Rate 31	$ -	$ 2,366,464	$ -	$ 202,225		$ 2,568,689	$ 0.0305	$ 0.0046	$ 0.0351	$ 1,510,235
49		Energy Charge--Rate 41	$ -	$ 24,799	$ -	$ 2,119		$ 26,918	$ 0.0305	$ 0.0046	$ 0.0351	$ 15,826
50		Energy Charge--Rate 46	$ -	$ 35,755	$ -	$ 3,055		$ 38,810	$ 0.0305	$ 0.0046	$ 0.0351	$ 22,818
51		**Sub-Total**	$ -	$ 2,427,018	$ -	$ 207,399	$ -	$ 2,634,417				$ 1,548,879
52	53	Residential & Farm Time of Use	$ 2,592	$ 25,925	$ -	$ 541		$ 29,058	$ 0.0903	$ 0.0024	$ 0.0927	$ 20,043
53	54	General Service Time of Use	$ 2,592	$ 52,893	$ 68,152	$ 2,650		$ 126,287	$ 0.0903	$ 0.0024	$ 0.0927	$ 98,261
54	60	Standby Service	$ -	$ -	$ 66,840	$ -		$ 66,840				$ 27,480
55	70	Full Interruptible Service	$ 308,880	$ 18,916,092	$ 4,105,594	$ (189,540)	$ 3,441	$ 23,144,467	$ 0.0497	$ (0.0006)	$ 0.0491	$ 18,612,828
56	71	Partial Interruptible Service	$ 36,960	$ 1,383,228	$ 743,979	$ (13,860)	$ 782	$ 2,151,089	$ 0.0497	$ (0.0006)	$ 0.0491	$ 1,361,052

Dakota Electric Association			Revenue under Present Rates						Cost of Power-Present Rates			
								DEA1 p14-20	Base		Net	
Line	Rate	Rate	Fixed	Energy	Demand	RTA (3)	Other (4)	Total	Cost of	PCA in	Cost of	
No.	Schedule	Class	Charge	Charge	Charge	Charge	Chg/Credits	Revenue	Power	RTA	Power	$
			=(a*j)*12	=(b*k+c*l+d*m)	=(f*n+g*o+h*p)	=(e*t)		(u+v+w+x+y)			=(u+v)	=(e*ac)
			(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)
57	80	Controlled Air Conditioning Service										
58		Option 1	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
59		Option 2										
60		Residential Rate 8131	$ -	$ (155,477)	$ -	$ -		$ (155,477)	$ -	$ -	$ -	$ -
61		Rate 8141	$ -	$ (6,923)	$ -	$ -		$ (6,923)	$ -	$ -	$ -	$ -
62		Rate 8146	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
63		**Sub-Total**	$ -	$ (162,400)	$ -	$ -	$ -	$ (162,400)				$ -
64		Option 3										
65		Residential Rate 8231		$ -	$ -	$ -	$ (1,371,162)	$ (1,371,162)				
66		Commercial		$ -	$ -	$ -	$ -	$ -				$ -
67		**Sub-Total**	$ -	$ -	$ -	$ -	$ (1,371,162)	$ (1,371,162)				$ -
68		Option 4										
69		Rate 8441		$ -	$ -	$ -	$ (91,631)	$ (91,631)				
70		Rate 8446		$ -	$ -	$ -	$ -	$ -				$ -
71		**Sub-Total**	$ -	$ -	$ -	$ -	$ (91,631)	$ (91,631)				$ -
72		Current Cost of Power Adj (Carryover) (9)										$ 3,503,288
73		Current Cost of Power Adj (Other) (10)										$ (631,855)
74		**Wellspring**						$ 23,370				$ 23,370
75		**Grand Total**	$ 15,237,350	$ 163,489,070	$ 19,868,162	$ 3,394,369	$ (1,532,010)	$ 200,480,311				$ 150,649,466
		Check Total						$ 200,480,307				$ 150,649,466
		Difference						$ 4				**$ -**
				$ 0.0903488								

Dakota Electric Association			Present	Proposed Rates (5)							
			Distribution	Fixed	Energy Charge			Demand Charge			
Line	Rate	Rate	Revenue	Charge	Summer	Winter	Other	Summer	Winter	Other	
No.	Schedule	Class		per Mo.	per kWh	per kWh	per kWh	per kW	per kW	per kW	RTA
			=(z-ad)								
			(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)
1	31	Residential & Farm Service	$ 36,641,136	$ 10.00	$ 0.1379		$ 0.1239				$-
2	32	Residential & Farm Demand Control	$ 7,629	$ 13.00	$ 0.0810		$ 0.0810	$ 15.50		$11.90	$-
	33	Electric Vehicle	$ 18,466		$ 0.0756	$ 0.4421	$ 0.1379	$ 0.1239			
3	36	Irrigation Service - Firm Rate	$ 35,077	$ 30.00	$ 0.0521		$ 0.0521	$ 26.60	$ 21.20	$15.67	$-
4	36	Irrigation Service - Controlled Rate	$ 479,043	$ 30.00	$ 0.0521		$ 0.0521	$ 4.55	$ 4.55	$ 4.55	$-
5	41	Small General Service	$ 1,856,374	$ 15.00	$ 0.1375		$ 0.1235				$-
6	44	Security Lighting Service	$ (36,585)								
7		175 W MV	$ -	$ -							
8		100 W HPS	$ 99,263	$ 12.01							
9		150 W HPS	$ 576	$ 14.26							
10		250 W HPS	$ 1,516	$ 18.83							
11		**Sub-Total**	$ 64,770								
12	44-2	Street Lighting Service	$ (216,956)								
13		175 W MV	$ -	$ 17.44							
14		250 W MV	$ 654	$ 20.93							
15		400 W MV	$ -	$ 26.89							
16		100 W HPS	$ 5,595	$ 13.80							
17		150 W HPS	$ 109,768	$ 15.97							
18		250 W HPS	$ 343,994	$ 20.54							
19		400 W HPS	$ 269	$ 25.42							
20		**Sub-Total**	$ 243,324								
21	44-1	Street Lighting Service	$ (46,997)								
22		175 W MV	$ -	$ 13.25							
23		250 W MV	$ -	$ 16.74							
24		400 W MV	$ -	$ 22.71							
25		100 W HPS	$ -	$ 9.61							
26		150 W HPS	$ 11,466	$ 11.78							
27		200 W HPS	$ 13,829	$ 14.18							
28		250 W HPS	$ 43,248	$ 16.35							
29		400 W HPS	$ 2,757	$ 21.24							
30		**Sub-Total**	$ 24,303								
31	44-3	Custom Residential Street Lighting	$ (608,937)								
32		175 W MV	$ -	$ -							
33		50 W HPS	$ 6,512	$ 8.45							
34		100 W HPS	$ 849,343	$ 10.39							
35		150 W HPS	$ 461,275	$ 12.63							
36		250 W HPS	$ 676	$ 17.21							
37		**Sub-Total**	$ 708,869								
	44-4	LED Security Lighting	$ 25,093	$ 7.75							
	44-5	LED Street Lighting Member Owned	$ (786)								
		A	$ -	$ 5.50							
		B	$ -	$ 7.75							
		C	$ 1,275	$ 11.16							
		D	$ -	$ 15.04							
		E	$ -	$ 19.07							
		Sub-Total	$ 489								
	44-6	LED Street Lighting	$ (18,234)								
		Standard Coach Post	$ 15,391	$ 9.30							
		Standard Acorn Post	$ 6,474	$ 10.85							
		Standard Cobra Mast	$ 9,075	$ 8.60							
		Standard Shoebox	$ 19,407	$ 10.70							
		Basic Coach Post	$ 3,360	$ 6.36							
		Basic Acorn Post	$ -	$ 6.12							
		Basic Cobra Mast	$ 4,140	$ 6.98							
		Basic Shoebox	$ 1,532	$ 8.68							
		Sub-Total	41,145								
38	45	Low Wattage Unmetered Service	$ 8,520	$ 10.50							
39	46	General Service	$ 7,434,366	$ 34.00	$ 0.0776	$ 0.0676	$ 0.0576	$ 13.70		$10.60	$-
40	47	Municipal Civil Defense Sirens	$ 3,960	$ 5.00							
41	49	Geothermal Heat Pump	$ 2,868		$ 0.1030	$ 0.1030	$ 0.1030				
42	51	Controlled Off-peak Energy Storage									
43		Energy Net Charge--Rate 31	$ 246,072		$ 0.0487	$ 0.0487	$ 0.0487				
44		Energy Charge--Rate 41	$ 1,112		$ 0.0487	$ 0.0487	$ 0.0487				
45		Energy Charge--Rate 46	$ 1,240		$ 0.0487	$ 0.0487	$ 0.0487				
46		**Sub-Total**	$ 248,424								
47	52	Interruptible Heating Service									
48		Energy Net Charge--Rate 31	$ 1,058,454		$ 0.0631	$ 0.0631	$ 0.0631				
49		Energy Charge--Rate 41	$ 11,092		$ 0.0631	$ 0.0631	$ 0.0631				
50		Energy Charge--Rate 46	$ 15,992		$ 0.0631	$ 0.0631	$ 0.0631				
51		**Sub-Total**	$ 1,085,538								
52	53	Residential & Farm Time of Use	$ 9,015	$ 13.00	$ 0.2126	$ 0.1986	$ 0.0945				$-
53	54	General Service Time of Use	$ 28,026	$ 36.00	$ 0.0521		$ 5.25	$ 26.14	$ 19.91	$13.67	$-
54	60	Standby Service	$ 39,360				$ 3.89	$ 3.21	$ 2.47	$ 1.74	
55	70	Full Interruptible Service	$ 4,531,639	$ 130.00	$ 0.0521		$ 5.25	$ 26.14	$ 19.91	$13.67	$-
56	71	Partial Interruptible Service	$ 790,037	$ 130.00	$ 0.0521		$ 5.25	$ 26.14	$ 19.91	$13.67	$-

Dakota Electric Association			Present	Proposed Rates (5)								
			Distribution	Fixed	Energy Charge			Demand Charge				
Line	Rate	Rate	Revenue	Charge	Summer	Winter	Other	Summer	Winter	Other		
No.	Schedule	Class		per Mo.	per kWh	per kWh	per kWh	per kW	per kW	per kW	RTA
			=(z-ad)								
			(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)
57	80	Controlled Air Conditioning Service									
58		Option 1	$ -								
59		Option 2									
60		Residential Rate 8131	$ (155,477)		$ (0.0320)						
61		Rate 8141	$ (6,923)		$ (0.0320)						
62		Rate 8146	$ -		$ (0.0320)						
63		**Sub-Total**	$ (162,400)								
64		Option 3									
65		Residential Rate 8231	$ (1,371,162)	$ (13.00)							
66		Commercial	$ -	$ (13.00)							
67		**Sub-Total**	$ (1,371,162)								
68		Option 4									
69		Rate 8441	$ (91,631)	$ (6.50)							
70		Rate 8446	$ -	$ (6.50)							
71		**Sub-Total**	$ (91,631)								
72		Current Cost of Power Adj (Carryover) (9)	$ (3,503,288)								
73		Current Cost of Power Adj (Other) (10)	$ 631,855								
74		**Wellspring**	$ -								
75		**Grand Total**	$ 49,830,845								
		Check Total	$ 49,830,841								
		Difference	**$ 4**								

Dakota Electric Association			Revenue under Proposed Rates (5)					
								Ex DEA-5 p3-9
Line No.	Rate Schedule	Rate Class	Fixed Charge	Energy Charge	Demand Charge	RTA Charge	Other (4) Chg/Credits	Total Revenue
			=(a*af)*12	=(b*ag+c*ah+d*a	=(f*aj+g*ak+h*a	=(e*am)		=(an+ao+ap+aq+a
			(an)	(ao)	(ap)	(aq)	(ar)	(as)
1	31	Residential & Farm Service	$ 12,024,240	$ 107,437,647	$ -	$ -	$ (72,216)	$ 119,389,671
2	32	Residential & Farm Demand Control	$ 2,340	$ 30,618	$ 11,571	$ -	$ -	$ 44,529
	33	Electric Vehicle		$ 26,505				$ 26,505
3	36	Irrigation Service - Firm Rate	$ 2,880	$ 8,468	$ 39,137	$ -	$ -	$ 50,485
4	36	Irrigation Service - Controlled Rate	$ 138,240	$ 406,450	$ 338,463	$ -	$ -	$ 883,153
5	41	Small General Service	$ 797,580	$ 5,400,980	$ -	$ -	$ (1,224)	$ 6,197,336
6	44	Security Lighting Service						
7		175 W MV	$ -	$ -	$ -	$ -	$ -	$ -
8		100 W HPS	$ 118,034	$ -	$ -	$ -	$ -	$ 118,034
9		150 W HPS	$ 684	$ -	$ -	$ -	$ -	$ 684
10		250 W HPS	$ 1,808	$ -	$ -	$ -	$ -	$ 1,808
11		**Sub-Total**	$ 120,526	$ -	$ -	$ -	$ -	$ 120,526
12	44-2	Street Lighting Service						
13		175 W MV	$ -	$ -	$ -	$ -	$ -	$ -
14		250 W MV	$ 753	$ -	$ -	$ -	$ -	$ 753
15		400 W MV	$ -	$ -	$ -	$ -	$ -	$ -
16		100 W HPS	$ 6,293	$ -	$ -	$ -	$ -	$ 6,293
17		150 W HPS	$ 123,799	$ -	$ -	$ -	$ -	$ 123,799
18		250 W HPS	$ 393,629	$ -	$ -	$ -	$ -	$ 393,629
19		400 W HPS	$ 305	$ -	$ -	$ -	$ -	$ 305
20		**Sub-Total**	$ 524,779	$ -	$ -	$ -	$ -	$ 524,779
21	44-1	Street Lighting Service						
22		175 W MV	$ -	$ -	$ -	$ -	$ -	$ -
23		250 W MV	$ -	$ -	$ -	$ -	$ -	$ -
24		400 W MV	$ -	$ -	$ -	$ -	$ -	$ -
25		100 W HPS	$ -	$ -	$ -	$ -	$ -	$ -
26		150 W HPS	$ 14,277	$ -	$ -	$ -	$ -	$ 14,277
27		200 W HPS	$ 17,186	$ -	$ -	$ -	$ -	$ 17,186
28		250 W HPS	$ 53,366	$ -	$ -	$ -	$ -	$ 53,366
29		400 W HPS	$ 3,313	$ -	$ -	$ -	$ -	$ 3,313
30		**Sub-Total**	$ 88,142	$ -	$ -	$ -	$ -	$ 88,142
31	44-3	Custom Residential Street Lighting						
32		175 W MV	$ -	$ -	$ -	$ -	$ -	$ -
33		50 W HPS	$ 8,213	$ -	$ -	$ -	$ -	$ 8,213
34		100 W HPS	$ 1,049,307	$ -	$ -	$ -	$ -	$ 1,049,307
35		150 W HPS	$ 565,622	$ -	$ -	$ -	$ -	$ 565,622
36		250 W HPS	$ 826	$ -	$ -	$ -	$ -	$ 826
37		**Sub-Total**	$ 1,623,968					$ 1,623,968
	44-4	LED Security Lighting	$ 31,434	$ -	$ -	$ -	$ -	$ 31,434
	44-5	LED Street Lighting Member Owned						
		A	$ -	$ -	$ -	$ -	$ -	$ -
		B	$ -	$ -	$ -	$ -	$ -	$ -
		C	$ 1,473	$ -	$ -	$ -	$ -	$ 1,473
		D	$ -	$ -	$ -	$ -	$ -	$ -
		E	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	$ 1,473					$ 1,473
	44-6	LED Street Lighting						
		Standard Coach Post	$ 13,504	$ -	$ -	$ -	$ -	$ 13,504
		Standard Acorn Post	$ 6,250	$ -	$ -	$ -	$ -	$ 6,250
		Standard Cobra Mast	$ 9,391	$ -	$ -	$ -	$ -	$ 9,391
		Standard Shoebox	$ 19,388	$ -	$ -	$ -	$ -	$ 19,388
		Basic Coach Post	$ 3,129	$ -	$ -	$ -	$ -	$ 3,129
		Basic Acorn Post	$ -	$ -	$ -	$ -	$ -	$ -
		Basic Cobra Mast	$ 4,439	$ -	$ -	$ -	$ -	$ 4,439
		Basic Shoebox	$ 1,667	$ -	$ -	$ -	$ -	$ 1,667
		Sub-Total	57,768	-	-	-	-	57,768
38	45	Low Wattage Unmetered Service	$ 8,946	$ -	$ -	$ -	$ -	$ 8,946
39	46	General Service	$ 1,122,000	$ 33,489,216	$ 16,572,750	$ -	$ -	$ 51,183,966
40	47	Municipal Civil Defense Sirens	$ 3,960	$ -	$ -	$ -	$ -	$ 3,960
41	49	Geothermal Heat Pump		$ 17,798				$ 17,798
42	51	Controlled Off-peak Energy Storage						
43		Energy Net Charge--Rate 31	$ -	$ 497,249	$ -	$ -	$ -	$ 497,249
44		Energy Charge--Rate 41	$ -	$ 2,245	$ -	$ -	$ -	$ 2,245
45		Energy Charge--Rate 46	$ -	$ 2,506	$ -	$ -	$ -	$ 2,506
46		**Sub-Total**	$ -	$ 502,000	$ -	$ -	$ -	$ 502,000
47	52	Interruptible Heating Service						
48		Energy Net Charge--Rate 31	$ -	$ 2,714,980	$ -	$ -	$ -	$ 2,714,980
49		Energy Charge--Rate 41	$ -	$ 28,451	$ -	$ -	$ -	$ 28,451
50		Energy Charge--Rate 46	$ -	$ 41,021	$ -	$ -	$ -	$ 41,021
51		**Sub-Total**	$ -	$ 2,784,452	$ -	$ -	$ -	$ 2,784,452
52	53	Residential & Farm Time of Use	$ 2,808	$ 27,515	$ -	$ -	$ -	$ 30,323
53	54	General Service Time of Use	$ 2,592	$ 55,225	$ 72,725	$ -	$ -	$ 130,542
54	60	Standby Service	$ -	$ -	$ 74,160	$ -	$ -	$ 74,160
55	70	Full Interruptible Service	$ 365,040	$ 19,750,068	$ 4,536,379	$ -	$ 3,441	$ 24,654,928
56	71	Partial Interruptible Service	$ 43,680	$ 1,444,212	$ 810,785	$ -	$ 782	$ 2,299,459

Dakota Electric Association			Revenue under Proposed Rates (5)					
								Ex DEA-5 p3-9
Line	Rate	Rate	Fixed	Energy	Demand	RTA	Other (4)	Total
No.	Schedule	Class	Charge	Charge	Charge	Charge	Chg/Credits	Revenue
			=(a*af)*12	=(b*ag+c*ah+d*a	=(f*aj+g*ak+h*a	=(e*am)		=(an+ao+ap+aq+a
			(an)	(ao)	(ap)	(aq)	(ar)	(as)
57	80	Controlled Air Conditioning Service						
58		Option 1	$ -	$ -	$ -	$ -	$ -	$ -
59		Option 2						
60		Residential Rate 8131	$ -	$ (155,477)	$ -	$ -	$ -	$ (155,477)
61		Rate 8141	$ -	$ (6,923)	$ -	$ -	$ -	$ (6,923)
62		Rate 8146	$ -	$ -	$ -	$ -	$ -	$ -
63		**Sub-Total**	$ -	$ (162,400)	$ -	$ -	$ -	$ (162,400)
64		Option 3						
65		Residential Rate 8231	$ -	$ -	$ -	$ -	$ (1,371,162)	$ (1,371,162)
66		Commercial	$ -	$ -	$ -	$ -	$ -	$ -
67		**Sub-Total**	$ -	$ -	$ -	$ -	$ (1,371,162)	$ (1,371,162)
68		Option 4						
69		Rate 8441	$ -	$ -	$ -	$ -	$ (91,631)	$ (91,631)
70		Rate 8446	$ -	$ -	$ -	$ -	$ -	$ -
71		**Sub-Total**	$ -	$ -	$ -	$ -	$ (91,631)	$ (91,631)
72		Current Cost of Power Adj (Carryover) (9)						
73		Current Cost of Power Adj (Other) (10)						
74		**Wellspring**						$ 23,370
75		**Grand Total**	$ 16,962,396	$ 171,218,754	$ 22,455,970	$ -	$ (1,532,010)	$ 209,128,481
		Check Total						$ 209,128,484
		Difference						$ (3)

Dakota Electric Association			Cost of Power-Proposed Rates (6)				Proposed (7)	Increase Present to Proposed	
			Base		Net		Distribution	Total (8)	Distribution
Line	Rate	Rate	Cost of	PCA in	Cost of		Revenue	Revenue	Revenue
No.	Schedule	Class	Power	RTA	Power	$	$	$	$
			r)			=(e*av)	=(as-aw)	=(as-z)	=(ax-ae)
			(at)	(au)	(av)	(aw)	(ax)	(ay)	(az)
1	31	Residential & Farm Service	$ 0.0939	$ -	$ 0.0939	$ 78,696,607	$ 40,693,064	$ 5,057,636	$ 4,051,928
2	32	Residential & Farm Demand Control	$ 0.0939	$ -	$ 0.0939	$ 35,494	$ 9,035	$ 1,859	$ 1,406
	33	Electric Vehicle	$ 0.0204	$ -	$ 0.0204	$ 6,140	$ 20,365	$ 1,869	$ 1,899
3	36	Irrigation Service - Firm Rate	$ 0.0939	$ -	$ 0.0939	$ 15,261	$ 35,224	$ 342	$ 147
4	36	Irrigation Service - Controlled Rate	$ 0.0521	$ -	$ 0.0521	$ 406,450	$ 476,703	$ 21,064	$ (2,340)
5	41	Small General Service	$ 0.0939	$ -	$ 0.0939	$ 3,994,281	$ 2,203,055	$ 397,726	$ 346,681
6	44	Security Lighting Service	$ 0.0939	$ -	$ 0.0939	$ 38,086	$ (38,086)	$ (1,014)	$ (1,501)
7		175 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
8		100 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 118,034	$ 18,771	$ 18,771
9		150 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 684	$ 108	$ 108
10		250 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 1,808	$ 292	$ 292
11		**Sub-Total**	$ 0.0939	$ -	$ 0.0939	$ 38,086	$ 82,440	$ 18,157	$ 17,670
12	44-2	Street Lighting Service	$ 0.0939	$ -	$ 0.0939	$ 225,856	$ (225,856)	$ (6,013)	$ (8,900)
13		175 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
14		250 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ 753	$ 99	$ 99
15		400 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
16		100 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 6,293	$ 698	$ 698
17		150 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 123,799	$ 14,031	$ 14,031
18		250 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 393,629	$ 49,635	$ 49,635
19		400 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 305	$ 36	$ 36
20		**Sub-Total**	$ 0.0939	$ -	$ 0.0939	$ 225,856	$ 298,923	$ 58,486	$ 55,599
21	44-1	Street Lighting Service	$ 0.0939	$ -	$ 0.0939	$ 48,926	$ (48,926)	$ (1,303)	$ (1,929)
22		175 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
23		250 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
24		400 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
25		100 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
26		150 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 14,277	$ 2,811	$ 2,811
27		200 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 17,186	$ 3,357	$ 3,357
28		250 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 53,366	$ 10,118	$ 10,118
29		400 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 3,313	$ 556	$ 556
30		**Sub-Total**	$ 0.0939	$ -	$ 0.0939	$ 48,926	$ 39,216	$ 15,539	$ 14,913
31	44-3	Custom Residential Street Lighting	$ 0.0939	$ -	$ 0.0939	$ 633,915	$ (633,915)	$ (16,877)	$ (24,978)
32		175 W MV	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
33		50 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 8,213	$ 1,701	$ 1,701
34		100 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 1,049,307	$ 199,964	$ 199,964
35		150 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 565,622	$ 104,347	$ 104,347
36		250 W HPS	$ 0.0939	$ -	$ 0.0939	$ -	$ 826	$ 150	$ 150
37		**Sub-Total**				$ 633,915	$ 990,053	$ 289,285	$ 281,184
	44-4	LED Security Lighting	$ 0.0939	$ -	$ 0.0939	$ 6,094	$ 25,340	$ 325	$ 247
	44-5	LED Street Lighting Member Owned	$ 0.0939	$ -	$ 0.0939	$ 818	$ (818)	$ (22)	$ (32)
		A	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
		B	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
		C	$ 0.0939	$ -	$ 0.0939	$ -	$ 1,473	$ 198	$ 198
		D	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
		E	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
		Sub-Total				$ 818	$ 655	$ 176	$ 166
	44-6	LED Street Lighting	$ 0.0939	$ -	$ 0.0939	$ 18,982	$ (18,982)	$ (505)	$ (748)
		Standard Coach Post	$ 0.0939	$ -	$ 0.0939	$ -	$ 13,504	$ (1,887)	$ (1,887)
		Standard Acorn Post	$ 0.0939	$ -	$ 0.0939	$ -	$ 6,250	$ (224)	$ (224)
		Standard Cobra Mast	$ 0.0939	$ -	$ 0.0939	$ -	$ 9,391	$ 316	$ 316
		Standard Shoebox	$ 0.0939	$ -	$ 0.0939	$ -	$ 19,388	$ (19)	$ (19)
		Basic Coach Post	$ 0.0939	$ -	$ 0.0939	$ -	$ 3,129	$ (231)	$ (231)
		Basic Acorn Post	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
		Basic Cobra Mast	$ 0.0939	$ -	$ 0.0939	$ -	$ 4,439	$ 299	$ 299
		Basic Shoebox	$ 0.0939	$ -	$ 0.0939	$ -	$ 1,667	$ 135	$ 135
		Sub-Total				18,982	$ 38,786	$ (2,116)	$ (2,359)
38	45	Low Wattage Unmetered Service					$ 8,946	$ 426	$ 426
39	46	General Service	$ 0.0939	$ -	$ 0.0939	$ 43,381,800	$ 7,802,166	$ 922,200	$ 367,800
40	47	Municipal Civil Defense Sirens					$ 3,960	$ -	$ -
41	49	Geothermal Heat Pump	$ 0.0813	$ -	$ 0.0813	$ 14,049	$ 3,749	$ 1,227	$ 881
42	51	Controlled Off-peak Energy Storage							
43		Energy Net Charge--Rate 31	$ 0.0204	$ -	$ 0.0204	$ 208,293	$ 288,956	$ 41,863	$ 42,884
44		Energy Charge--Rate 41	$ 0.0204	$ -	$ 0.0204	$ 941	$ 1,304	$ 188	$ 192
45		Energy Charge--Rate 46	$ 0.0204	$ -	$ 0.0204	$ 1,050	$ 1,456	$ 211	$ 216
46		**Sub-Total**	$ 0.0204	$ -	$ 0.0204	$ 210,283	$ 291,717	$ 42,262	$ 43,293
47	52	Interruptible Heating Service							
48		Energy Net Charge--Rate 31	$ 0.0352	$ -	$ 0.0352	$ 1,514,537	$ 1,200,443	$ 146,291	$ 141,989
49		Energy Charge--Rate 41	$ 0.0352	$ -	$ 0.0352	$ 15,871	$ 12,580	$ 1,533	$ 1,488
50		Energy Charge--Rate 46	$ 0.0352	$ -	$ 0.0352	$ 22,883	$ 18,138	$ 2,211	$ 2,146
51		**Sub-Total**				$ 1,553,291	$ 1,231,161	$ 150,035	$ 145,623
52	53	Residential & Farm Time of Use	$ 0.0939	$ -	$ 0.0939	$ 20,303	$ 10,020	$ 1,265	$ 1,005
53	54	General Service Time of Use	$ 0.0939	$ -	$ 0.0939	$ 99,532	$ 31,010	$ 4,255	$ 2,984
54	60	Standby Service				$ 27,480	$ 46,680	$ 7,320	$ 7,320
55	70	Full Interruptible Service	$ 0.0521	$ -	$ 0.0521	$ 19,750,068	$ 4,904,860	$ 1,510,461	$ 373,221
56	71	Partial Interruptible Service	$ 0.0521	$ -	$ 0.0521	$ 1,444,212	$ 855,247	$ 148,370	$ 65,210

Dakota Electric Association			Cost of Power-Proposed Rates (6)				Proposed (7)	Increase Present to Proposed	
			Base		Net		Distribution	Total (8)	Distribution
Line	Rate	Rate	Cost of	PCA in	Cost of		Revenue	Revenue	Revenue
No.	Schedule	Class	Power	RTA	Power	$	$	$	$
			r)			=(e*av)	=(as-aw)	=(as-z)	=(ax-ae)
			(at)	(au)	(av)	(aw)	(ax)	(ay)	(az)
57	80	Controlled Air Conditioning Service							
58		Option 1	$ 0.0939	$ -	$ 0.0939	$ -	$ -	$ -	$ -
59		Option 2							
60		Residential Rate 8131	$ -	$ -	$ -	$ -	$ (155,477)	$ -	$ -
61		Rate 8141	$ -	$ -	$ -	$ -	$ (6,923)	$ -	$ -
62		Rate 8146	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63		**Sub-Total**				$ -	$ (162,400)	$ -	$ -
64		Option 3							
65		Residential Rate 8231	$ -	$ -	$ -	$ -	$ (1,371,162)	$ -	$ -
66		Commercial	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67		**Sub-Total**				$ -	$ (1,371,162)	$ -	$ -
68		Option 4							
69		Rate 8441	$ -	$ -	$ -	$ -	$ (91,631)	$ -	$ -
70		Rate 8446	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		**Sub-Total**				$ -	$ (91,631)	$ -	$ -
72		Current Cost of Power Adj (Carryover) (9)							$ 3,503,288
73		Current Cost of Power Adj (Other) (10)							$ (631,855)
74		**Wellspring**				$ 23,370	$ -		$ -
75		**Grand Total**				$ 150,651,298	$ 58,477,183	$ 8,648,170	$ 8,646,338
		Check Total				$ 150,649,466	$ 58,479,018	$ 8,648,177	$ 8,648,177
		Difference				$ 1,832	$ (1,835)	(7)	(1,839)

Dakota Electric Association			Billing Units (1)									
			Avg. No. of	Energy					Demand			
Line	Rate	Rate	Consumers	Summer	Other			Total	Summer	Winter	Other	Total
No.	Schedule	Class	(2019 Budget)	(kWh)	(kWh)			(kWh)	(kW)	(kW)	(kW)	(kW)
								=(b+c+d)				=(f+g+h)
			(a)	(b)	(c)	(d)		(e)	(f)	(g)	(h)	(i)

Notes:

The numbers contained in the above cells are for illustrative purposes only.

(1) Test Year Billing Units per Exhibit_(DEA-1)

(2) Present Rates and Present Revenue per Exhibit_(DEA-1) pages 13 - 20.

(3) RTA Charge / (Credit) equals 2014 RTA from Schedule A1 of January 2014 RTA filing, Docket No. E-111/M-14-46.

(4) Other Charges / (Credits) include controlled water heating credits, primary voltage & metering discounts, rate 70 failure to control and rate 71 coincident demand charges, controlled air conditioning credits.

(5) Proposed Rates and Proposed Revenue per Exhibit_(DEA-5) pages 3 - 9.

(6) Proposed Base Cost of Power per Exhibit _(DEA-12) and Proposed Cost of Power per Exhibit_(DEA-1) page 20.

(7) Distribution cost of service summarized on Ex DEA-3 Page 2.

(8) Increase in Total Revenue Present to Proposed per Exhibit_(DEA-6) page 6.

(9) This adjustment accounts for the prior year recovery balances inlcuded in the current RTA calculation

(10) This adjustment attempts to account for the differences in other power costs

Workpaper 23
Street Light Analysis

Security and Street Lighting Cost Analysis

Summary of Monthly Costs by Component

	Power Supply Costs		Allocated Distribution		Maintenance				Capital Cost			
Light Size & Type	**PS Energy**	**PS Demand**	**Consumer**	**Capacity**	**44**	**44-1**	**44-2**	**44-3**	**44**	**44-1**	**44-2**	**44-3**
	($/mo.) [1]	($/mo.) [1]	($/mo.) [2]	($/mo.) [2]	($/mo.) [3]	($/mo.) [3]	($/mo.) [3]	($/mo.) [3]	($/mo.) [4]	($/mo.)	($/mo.) [4]	($/mo.)
175 W MV	$3.35	$1.72	$3.09	$3.30	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
250 W MV	$4.76	$2.46	$3.09	$4.69	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
400 W MV	$7.14	$3.69	$3.09	$7.03	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
50 W HPS	$1.12	$0.57	$3.09	$1.10	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
100 W HPS	$2.14	$1.11	$3.09	$1.48	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
150 W HPS	$3.21	$1.64	$3.09	$2.10	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
200 W HPS	$4.08	$2.09	$3.09	$3.16	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
250 W HPS	$4.95	$2.54	$3.09	$4.02	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	
400 W HPS	$7.58	$3.89	$3.09	$4.88	$2.54	$1.76	$2.58	$2.58	$1.68		$3.36	

1 See pages 2 and 3 of this workpaper for the determination of power supply energy and capacity per unit costs.
2 See page 4 of this workpaper for the determination of allocated distribution per unit costs.
3 See page 5 of this workpaper for the determination of monthly maintenance costs by rate schedule.
4 See page 6 of this workpaper for the determination of capital costs by rate schedule.

Workpaper 23
Page 1 of 17

Security and Street Lighting Cost Analysis

Determination of Lighting Power Supply Energy Costs

	Energy *(est.)*				Energy Cost	
Security Lights	**Monthly Usage** [1]	**Monthly Purchased**	**Annual Used**	**Annual Purchased**	**Monthly**	**Annual**
	(kWh)	(kWh)	(kWh)	(kWh)	($/mo.)	($/yr.)
Mecury Vapor						
175 W MV	69	71	828	849	3.35	40.22
250 W MV	98	101	1,176	1,206	4.76	57.12
400 W MV	147	151	1,764	1,809	7.14	85.68
High Pressure Sodium						
50 W HPS	23	24	276	283	1.12	13.41
70 W HPS	31	32	372	382	1.51	18.07
100 W HPS	44	45	528	542	2.14	25.64
150 W HPS	66	68	792	812	3.21	38.47
200 W HPS	84	86	1,008	1,034	4.08	48.96
250 W HPS	102	105	1,224	1,255	4.95	59.45
400 W HPS	156	160	1,872	1,920	7.58	90.92
		Line Loss [2]			$/kWh [3]	
Assumptions/Notes:		2.5%			0.04736	

1 Based on lights being on from 1/2 hour after sunset to 1/2 hour before sunrise, or about 3,930 hours per year.
2 See Workpaper 10 for average system losses.
3 Reflects blended cost per kWh purchased.
6.23% On Peak at 5.948¢ per kWh plus 93.77% Off Peak at 4.655¢ per kWh.

Workpaper 23
Page 2 of 17

Security and Street Lighting Cost Analysis

Determination of Lighting Power Supply Demand Costs

Security Lights	Summer Non-Coinc. Demand	Summer Coincident Demand	Winter Non-Coinc. Demand	Winter Coincident Demand	Other Non-Coinc. Demand	Other Coincident Demand	Summer Demand Cost[1]	Winter Demand Cost[1]	Other Demand Cost[1]	Weighted Demand Cost
	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	($/mo.)	($/mo.)	($/mo.)	($/mo.)
Mercury Vapor										
175 W MV	0.210	-	0.21	0.21	0.21	0.11	-	4.08	1.40	1.72
250 W MV	0.300	-	0.30	0.30	0.30	0.15	-	5.83	2.00	2.46
400 W MV	0.450	-	0.45	0.45	0.45	0.23	-	8.74	3.00	3.69
High Pressure Sodium										
50 W HPS	0.070	-	0.07	0.07	0.07	0.04	-	1.36	0.47	0.57
70 W HPS	0.095	-	0.10	0.10	0.10	0.05	-	1.84	0.63	0.78
100 W HPS	0.135	-	0.14	0.14	0.14	0.07	-	2.62	0.90	1.11
150 W HPS	0.200	-	0.20	0.20	0.20	0.10	-	3.88	1.33	1.64
200 W HPS	0.255	-	0.26	0.26	0.26	0.13	-	4.95	1.70	2.09
250 W HPS	0.310	-	0.31	0.31	0.31	0.16	-	6.02	2.07	2.54
400 W HPS	0.475	-	0.48	0.48	0.48	0.24	-	9.22	3.17	3.89
		Coinc. Factor		Coinc. Factor		Coinc. Factor	$/kW	$/kW	$/kW	
		0%		100%		50%	$25.50	$19.42	$13.34	

[1] Reflects blended cost per kW purchased based on Exhibit (DEA - 8). See calculation below:

	Summer	Winter	Other
Capacity ($/kW)	$18.24	$12.16	$6.08
Transmission ($/kW)	$6.57	6.57	6.57
Ancillary ($/kW)	$0.69	0.69	0.69
GRE Total ($/kW)	$25.50	$19.42	$13.34

Workpaper 23
Page 3 of 17

Security and Street Lighting Cost Analysis

Determination of Allocated Distribution Costs

Description	COS Results [1]	Consumer-Related For System [2]		Capacity
	($)	(%)	($)	($)
Allocated Distribution				
Direct (Except Account #586)			-	
Administrative & General	279,634	55.7%	155,756	123,878
Miscellaneous Expense	12,343	55.7%	6,875	5,468
Depreciation	359,153	55.7%	200,048	159,105
Interest-LT	122,518	55.7%	68,243	54,275
Property Taxes	120,397	55.7%	67,061	53,336
Required Margin	224,114	55.7%	124,831	99,283
	1,118,159		622,815	495,344
Billing Units (Cons & MWh)			16,771	10,359
Per Unit Cost ($/light/mo. and $/kWh)			$ 3.09	$ 0.0478
Other Distribution - Per Unit Cost			$ -	$ -
Total Allocated Distribution			$ 3.09	$ 0.0478

[1] See Exhibit DEA__(DEA-3), pages 20 to 22.
[2] Reflects the percentage of distribution-related costs that have been classified as consumer related.

Security and Street Lighting Cost Analysis

Determination of Monthly Maintenance Costs

Description	Rate Schedule 44		Rate Schedule 44-1	
Rated Life (hours)		24,000		24,000
Hours of Lighting/Year		3,930		3,930
Materials				
Lamp	$	7.59	$	7.59
Photocell		6.80		6.80
Other				
Subtotal	$	14.39	$	14.39
Trips/Light/Yr. [1]		0.16		0.16
Annual Cost	$	2.36	$	2.36
Monthly Cost	$	0.20	$	0.20
Labor				
Crew Size		1		1
Hours [2]		1.5		1.0
Rate per hour	$	75.10	$	75.10
Truck Rate per hour	$	39.20	$	39.20
Subtotal	$	171.45	$	114.30
Trips/Light/Yr. [1]		0.16		0.16
Annual Cost	$	28.07	$	18.72
Monthly Cost	$	2.34	$	1.56
Total Annual Cost	$	30.43	$	21.07
Total Monthly Cost	$	2.54	$	1.76

	44		44-1	
Number of Lights (Historical)		912		471
Total Maintenance Cost	$	27,753	$	9,925
		Subtotal	$	37,679
Maintenance Cost Booked (Historical)			$	487,554
Remaining Maintenance Costs			$	449,875
Rate 44-2 and 44-3 Lights (Historical)				14,516
Maintenance Cost per Light			$	2.58

[1] Based on hours of lighting per year divided by rated hours of life.

[2] Rate 44 security lights average 1.5 hours due to rural location of security lights.

Security and Street Lighting Cost Analysis
Determination of Capital Recovery Factor and Cost

Description	44	44-1	44-2	44-3
Capital Cost Recovered in Rate	250 [1]	0	500	0
Depreciable Life (Years)	22.2 [2]	N.A.	22.2 [2]	N.A.
DEA Required Rate of Return [3]	5.73%	N.A.	5.73%	N.A.
Annual Capital Recovery Factor [4]	8.1%	N.A.	8.1%	N.A.
Annual Cost	$ 20.17	$ -	$ 40.35	$ -
Monthly Cost	$ 1.68	$ -	$ 3.36	$ -

[1] Based on DEA rate schedules.
[2] From DEA Depreciation Study, reflects a 20-year useful life and 10% salvage value.
[3] Reference DEA Exhibit__(DEA-2), Page 8.
[4] See the following formula:

$$\frac{\text{ROR \%} * ((1 + \text{ROR \%})^\wedge\text{Life})}{(1 + \text{ROR \%})^\wedge\text{Life - 1}}$$

LED Lighting Cost Analysis (DEA-Owned)

Summary of Monthly Costs by Component

Light Type	Power Supply Costs		Allocated Distribution		Capital	Maintenance	Total
	PS Energy	PS Demand	Consumer	Capacity	Recovery		
	($/mo.) [1]	($/mo.) [1]	($/mo.) [2]	($/mo.) [2]	($/mo.) [3]	($/mo.) [4]	($/mo.)
Security Light	$0.78	$0.40	$3.09	$0.77	$1.82	$0.89	$7.75
Street Light							
Cobra	$0.97	$0.50	$3.09	$0.96	$2.46	$0.60	$8.58
Shoebox	$1.65	$0.88	$3.09	$1.63	$2.84	$0.60	$10.69
Coach Light	$0.73	$0.39	$3.09	$0.72	$3.77	$0.60	$9.29
Acorn Light	$0.63	$0.33	$3.09	$0.62	$5.58	$0.60	$10.85

[1] See pages 2 and 3 for the determination of wholesale power supply energy and demand costs per unit.
[2] See page 4 for the determination of allocated distribution costs per unit.
[3] See page 5 for the determination of monthly capital recovery costs per unit.
[4] See page 6 for the determination of monthly maintenance costs per unit.

LED Lighting Cost Analysis (DEA-Owned)
Determination of Lighting Power Supply Energy Costs

Light Type	Energy (est.) Monthly Usage[1]	Monthly Purchased	Annual Used	Annual Purchased	Energy Cost Monthly	Annual
	(kWh)	(kWh)	(kWh)	(kWh)	($/mo.)	($/yr.)
Security Light	16	16	192	197	0.78	9.33
Street Light						
Cobra	20	21	240	246	0.97	11.66
Shoebox	34	35	408	418	1.65	19.82
Coach Light	15	15	180	185	0.73	8.74
Acorn Light	13	13	156	160	0.63	7.58
		Line Loss[2]			$/kWh[3]	
Assumptions/Notes:		2.5%			0.04736	

[1] Based on lights being on from 1/2 hour after sunset to 1/2 hour before sunrise, or about 3,930 hours per year.
[2] See Workpaper 10 for average system losses.
[3] Reflects blended cost per kWh purchased.
6.23% On Peak at 5.948¢ per kWh plus 93.77% at 4.655¢ per kWh.

Workpaper 23
Page 8 of 17

LED Lighting Cost Analysis (DEA-Owned)

Determination of Lighting Power Supply Demand Costs

Light Type	Summer Non-Coinc. Demand	Summer Coincident Demand	Winter Non-Coinc. Demand	Winter Coincident Demand	Other Non-Coinc. Demand	Other Coincident Demand	Summer Demand Cost [1]	Winter Demand Cost [1]	Other Demand Cost [1]	Weighted Demand Cost
	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	($/mo.)	($/mo.)	($/mo.)	($/mo.)
Security Light	0.048	-	0.048	0.048	0.048	0.024	-	0.955	0.328	0.40
Street Light										
Cobra	0.060	-	0.060	0.060	0.060	0.030	-	1.194	0.410	0.50
Shoebox	0.105	-	0.105	0.105	0.105	0.053	-	2.090	0.718	0.88
Coach Light	0.046	-	0.046	0.046	0.046	0.023	-	0.916	0.314	0.39
Acorn Light	0.039	-	0.039	0.039	0.039	0.020	-	0.776	0.267	0.33
		Coinc. Factor		Coinc. Factor		Coinc. Factor	$/kW	$/kW	$/kW	
		0%		100%		50%	$26.14	$19.91	$13.67	

[1] Reflects blended cost per kW purchased based on Exhibit (DEA - 8). See calculation below:

	Summer	Winter	Other
Capacity ($/kW)	$18.24	$12.16	$6.08
Transmission ($/kW)	$6.57	6.57	6.57
Ancillary ($/kW)	$0.69	0.69	0.69
GRE Total ($/kW)	$25.50	$19.42	$13.34
Line Loss	2.5%	2.5%	2.5%
	$ 26.14	$ 19.91	$ 13.67

Workpaper 23
Page 9 of 17

LED Lighting Cost Analysis (DEA-Owned)

Determination of Allocated Distribution Costs

Description	COS Results [1]	Consumer-Related For System [2]		Capacity
	($)	(%)	($)	($)
Allocated Distribution				
Direct (Except Account #586)				
Administrative & General	279,634	55.7%	155,756	123,878
Miscellaneous Expense	12,343	55.7%	6,875	5,468
Depreciation	359,153	55.7%	200,048	159,105
Interest-LT	122,518	55.7%	68,243	54,275
Property Taxes	120,397	55.7%	67,061	53,336
Required Margin	224,114	55.7%	124,831	99,283
	1,118,159		622,815	495,344
Billing Units (Cons/MWh)			16,771	10,359
Per Unit Cost ($/light/mo. and $/kWh)			$ 3.09	$ 0.0478
Other Distribution - Per Unit Cost			$ -	$ -
Total Allocated Distribution			$ 3.09	$ 0.0478

[1] See Exhibit (DEA-3), pages 20 to 22.
[2] Reflects the percentage of distribution-related costs that have been classified as consumer related.

LED Lighting Cost Analysis (DEA-Owned)

Determination of Capital Recovery Factor and Cost

Description		Light Type				
		Security	Coach	Acorn	Cobra	Shoebox
Installed Capital Cost	[1]	$ 249.55	$ 517.70	$ 765.50	$ 337.70	$ 389.70
Salvage Value	[2]	$ 24.96	$ 51.77	$ 76.55	$ 33.77	$ 38.97
Capital Cost Recovered in Rate		$ 224.60	$ 465.93	$ 688.95	$ 303.93	$ 350.73
Depreciable Life (Years)	[3]	16.0	16.0	16.0	16.0	16.0
DEA Required Rate of Return	[4]	5.73%	5.73%	5.73%	5.73%	5.73%
Annual Capital Recovery Factor	[5]	9.7%	9.7%	9.7%	9.7%	9.7%
Annual Cost		$ 21.81	$ 45.25	$ 66.91	$ 29.52	$ 34.06
Monthly Cost		$ 1.82	$ 3.77	$ 5.58	$ 2.46	$ 2.84

[1] Based on LED rate schedules. Reflects installed capital cost.
Acorn equipment assumed at 80% retrofit kits and 20% new fixtures.
[2] Estimated 10% salvage value.
[3] Reflects a 16-year useful life.
[4] Reference DEA Exhibit__(DEA-2), page 8.
[5] See the following formula:

$$\frac{\text{ROR \%} * ((1 + \text{ROR \%})\text{\^{}Life})}{(1 + \text{ROR \%})\text{\^{}Life} - 1}$$

LED Lighting Cost Analysis (DEA-Owned)

Determination of Monthly Maintenance Costs

Description	Light Type				
	Security	Coach	Acorn	Cobra	Shoebox
Hours of Lighting/Year	3,930	3,930	3,930	3,930	3,930
Hours of Lighting/Month	327.5	327.5	327.5	327.5	327.5
Materials					
NA					
Annual Cost	$ -	$ -	$ -	$ -	$ -
Monthly Cost	$ -	$ -	$ -	$ -	$ -
Labor					
Crew Size	1	1	1	1	1
Hours	1.5	1.0	1.0	1.0	1.0
Rate per hour	$ 75.10	$ 75.10	$ 75.10	$ 75.10	$ 75.10
Truck Rate per hour	$ 39.20	$ 39.20	$ 39.20	$ 39.20	$ 39.20
Subtotal	$ 171.45	$ 114.30	$ 114.30	$ 114.30	$ 114.30
Trips/Light/Year [1]	0.063	0.063	0.063	0.063	0.063
Annual Cost	$ 10.72	$ 7.14	$ 7.14	$ 7.14	$ 7.14
Monthly Cost	$ 0.89	$ 0.60	$ 0.60	$ 0.60	$ 0.60

1 Labor for all lights includes maintenance check at 8 years and replacement at 16 years.

Dakota Electric Association
LED Street Lighting (Schedule 44-6)
"Basic" Option Rate Calculations

	Description	*Coach*	*Acorn*	*Cobra*	*Shoebox*
	Proposed "Standard" LED Rate [1]	$ 9.29	$ 10.85	$ 8.58	$ 10.69
-	Fixture Replacement Component [2]	$ 3.77	$ 5.58	$ 2.46	$ 2.84
+	"Knock-Down" Replacement [3]	$ 0.84	$ 0.84	$ 0.84	$ 0.84
=	Proposed "Basic" Option LED Rates	$ 6.37	$ 6.12	$ 6.97	$ 8.69

Notes:

[1] See Exhibit DEA__(DEA-6), Page 3.

[2] See "Capital Recovery" costs in cost summary.

[3] Equals 5 year average annual knock-down replacement costs divided by number of DEA-owned street lights divided by 12 months.

LED Lighting Cost Analysis (Member-Owned)

Summary of Monthly Costs by Component

Light Type	Power Supply Costs		Allocated Distribution		Capital	Maintenance	Total
	PS Energy	PS Demand	Consumer	Capacity	Recovery		
	($/mo.) [1]	($/mo.) [1]	($/mo.) [2]	($/mo.) [2]	($/mo.) [3]	($/mo.) [4]	($/mo.)
Consumption Group							
A (40 to 80 watts)	$0.97	$0.50	$3.09	$0.96	$0.00	$0.00	$5.53
B (81 to 150 watts)	$1.85	$0.97	$3.09	$1.82	$0.00	$0.00	$7.72
C (151 to 250 watts)	$3.21	$1.68	$3.09	$3.16	$0.00	$0.00	$11.14
D (251 to 350 watts)	$4.76	$2.52	$3.09	$4.69	$0.00	$0.00	$15.06
E (351 to 450 watts)	$6.36	$3.36	$3.09	$6.26	$0.00	$0.00	$19.08

[1] See pages 2 and 3 for the determination of wholesale power supply energy and demand costs per unit.
[2] See page 4 for the determination of allocated distribution costs per unit.
[3] No Dakota Electric capital recovery costs for member-owned lights.
[4] No Dakota Electric maintenance costs for member-owned lights.

LED Lighting Cost Analysis (Member-Owned)

Determination of Lighting Power Supply Energy Costs

Light Type	Energy (est.)				Energy Cost	
	Monthly Usage [1]	Monthly Purchased	Annual Used	Annual Purchased	Monthly	Annual
	(kWh)	(kWh)	(kWh)	(kWh)	($/mo.)	($/yr.)
Consumption Group						
A (40 to 80 watts)	20	21	240	246	0.97	11.66
B (81 to 150 watts)	38	39	456	468	1.85	22.15
C (151 to 250 watts)	66	68	792	812	3.21	38.47
D (251 to 350 watts)	98	101	1,176	1,206	4.76	57.12
E (351 to 450 watts)	131	134	1,572	1,612	6.36	76.35
		Line Loss [2]			$/kWh [3]	
Assumptions/Notes:		2.5%			0.04736	

[1] Based on lights being on from 1/2 hour after sunset to 1/2 hour before sunrise, or about 3,930 hours per year.
[2] See Workpaper 10 for average system losses.
[3] Reflects blended cost per kWh purchased.
6.23% On Peak at 5.948¢ per kWh plus 93.77% at 4.655¢ per kWh.

Workpaper 23
Page 15 of 17

LED Lighting Cost Analysis (Member-Owned)

Determination of Lighting Power Supply Demand Costs

Light Type	Summer		Winter		Other		Summer Demand Cost [1]	Winter Demand Cost [1]	Other Demand Cost [1]	Weighted Demand Cost
	Non-Coinc. Demand	Coincident Demand	Non-Coinc. Demand	Coincident Demand	Non-Coinc. Demand	Coincident Demand				
	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	(kW-mo.)	($/mo.)	($/mo.)	($/mo.)	($/mo.)
Consumption Group										
A (40 to 80 watts)	0.060	-	0.060	0.060	0.060	0.030	-	1.194	0.410	0.50
B (81 to 150 watts)	0.115	-	0.115	0.115	0.115	0.058	-	2.289	0.786	0.97
C (151 to 250 watts)	0.200	-	0.200	0.200	0.200	0.100	-	3.981	1.367	1.68
D (251 to 350 watts)	0.300	-	0.300	0.300	0.300	0.150	-	5.972	2.051	2.52
E (351 to 450 watts)	0.400	-	0.400	0.400	0.400	0.200	-	7.962	2.735	3.36
		Coinc. Factor		Coinc. Factor		Coinc. Factor	$/kW	$/kW	$/kW	
		0%		100%		50%	$26.14	$19.91	$13.67	

[1] Reflects blended cost per kW purchased based on Exhibit (DEA - 8). See calculation below:

	Summer	Winter	Other
Capacity ($/kW)	$18.24	$12.16	$6.08
Transmission ($/kW)	$6.57	6.57	6.57
Ancillary ($/kW)	$0.69	0.69	0.69
GRE Total ($/kW)	$25.50	$19.42	$13.34
Line Loss	2.5%	2.5%	2.5%
	$ 26.14	$ 19.91	$ 13.67

Workpaper 23
Page 16 of 17

LED Lighting Cost Analysis (Member-Owned)

Determination of Allocated Distribution Costs

Description	COS Results [1]	Consumer-Related For System [2]		Capacity
	($)	(%)	($)	($)
Allocated Distribution				
Direct (Except Account #586)				
Administrative & General	279,634	55.7%	155,756	123,878
Miscellaneous Expense	12,343	55.7%	6,875	5,468
Depreciation	359,153	55.7%	200,048	159,105
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	1,118,159		622,815	495,344
Billing Units (Cons/MWh)			16,771	10,359
Per Unit Cost ($/light/mo. and $/kWh)			$ 3.09	$ 0.0478
Other Distribution - Per Unit Cost			$ -	$ -
Total Allocated Distribution			$ 3.09	$ 0.0478

[1] See Exhibit (DEA-3), pages 20 to 22.
[2] Reflects the percentage of distribution-related costs that have been classified as consumer related.

Workpaper 22
Guide to COS Study

GUIDE
TO THE
COST OF SERVICE STUDY

DAKOTA ELECTRIC ASSOCIATION

Updated: 9/11/19

Table of Contents

1. Introduction

This guide to Dakota Electric's cost of service study includes the following information:

- Overview of the COS and analysis,
- Description of Uniform System of Accounts included in the COS,
- Identification of account classifications,
- Review of account allocations,
- Summary of COS results, and
- List of related references.

2. COS Overview

The basic objective of Dakota Electric's cost of service study (COS) analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach meaning that 1) costs are allocated on an average system-wide basis, and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data and this has been confirmed by the Commission's approval of our cost of service study and methods in past rate cases.

A. COS Content

The content of Dakota Electric's COS is as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-7	Adjusted Statement of Operations
8-13	Classification of Revenue Requirements
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Analysis of Class Load Characteristics
25-40	Analysis of Class Demand Characteristics
41-42	Development of Allocation Factors

Analysis used to produce inputs to the COS include:

- Rate Class Weighting Factors

- Analysis of Class Load Characteristics
- Analysis of Class Demand Characteristics
- Minimum-Size System Analysis

Rate Class Weighting Factors - Page 23 of COS
The analysis of rate class weighting factors establishes a relative cost comparison (or weighting factor) between providing service to single phase versus three phase service consumers. These relative weighting factors are developed for plant including meters, service drops, transformers, and primary line.

Analysis of Class Load Characteristics - Page 24 of COS
The analysis of class load characteristics summarizes class billing determinants information including number of consumers in each class, energy sales, and billing demand. This analysis also summarizes demand estimates that are developed in the Analysis of Class Demand Characteristics shown on pages 25 through 40 of the COS.

Analysis of Class Demand Characteristics - Pages 25-40 of COS
The analysis of class demand characteristics estimates class seasonal coincident and non-coincident demands based on relative energy and demand billing determinant data as applicable. The overall estimates are adjusted to correspond to the Cooperative's total system coincident and non-coincident demands.

Minimum-Size System Analysis – Workpaper 21
The minimum-size system is one of two common methods used to classify certain distribution plant accounts between "consumer" and "demand." Dakota Electric was ordered to use the minimum-size method in future rate cases, or provide a justification as to why the Cooperative should continue to use the zero-intercept method. The analysis of the minimum-size method (with a demand adjustment) is contained in Workpaper 21.

B. Use of COS Results

It is important to recognize some of the inherent limitations of a COS. First, a COS analysis, while basically an engineering evaluation, is not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; and not as precise values.

Second, a COS analysis is directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as member acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need to keep the rate structure simple so that it is easily administered and understood by members.

With the above limitations in mind, a COS study can provide a useful guideline for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail members.

C. General Procedure for Conducting a COS

The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

- Step 1 Classify the plant account records into basic cost causative categories.
- Step 2 Classify the Test Year expenses and margin requirement into the same cost causative categories.
- Step 3 Develop allocation factors for each rate class.
- Step 4 Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

In this regard, it is important to note that Dakota Electric has used the same COS model that was approved in previous general rate cases, with minor refinements as ordered by the Commission.

D. Cost Causative Categories

Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.

Consumer - Costs that are the result of the number and location of each member and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense. In addition, a portion of distribution expenses is categorized using the results of the minimum size analysis.

Capacity - Costs which result from providing and maintaining in readiness for operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual member service peak. Much of the expense of operating and maintaining a three phase backbone feeder would generally fall within this category as would the
Demand Charge in the purchased power rate.

Energy - Costs which are related to the amount of energy used. The major item in this category is the Energy Charge in the purchased power rate.

E. Classification

The cost causative classification of the various electric plant accounts is presented in pages 4 and 5 of the COS. The classified accounts reflect the net plant balance for the Test Year. The methodology used in assigning the plant accounts to the cost causative categories is as follows:

Land, Structures, Station and Battery (Accts. 360 to 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.

Primary Line and Devices (Accts. 364, 365, 366, 367) - Assignment of the Primary Line and Device accounts was based on results of the "Minimum Size Method" to determine the consumer component share. A narrative and calculation of the minimum size method is provided in Workpaper 21. The remaining amount was then assigned to the capacity component.

Line Transformers (Acct. 368) - Classification of the Line Transformer account was approached in similar fashion using the "Minimum Size Method." (See Workpaper 21.) Again, it was reasoned that there exists a certain minimum transformer investment required to provide basic service to each consumer independent of energy usage or capacity requirements. This cost is assigned to the consumer component, while the remaining investment is considered capacity related.

Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.

Consumer Premise (Acct. 371) - The Consumer's Premises account is associated to lighting plant and was directly assigned to the Light Class.

Street Lighting (Acct. 373) - The street or security lighting account was assigned directly to the Lighting Class.

General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the general plant has minimal effect on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant was not warranted.

The factors used in the expense classification are summarized in pages 14 through 17 of the COS. The methodology and rationale for that methodology is discussed below:

Purchased Power (Acct. 555) - The Demand and Energy Charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively. This includes Transmission Charges which were assigned to the capacity component.

Distribution Operation and Maintenance (Accts. 580 - 598) - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 587, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.

Consumer Accounting (Accts. 901 - 905) - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.

Consumer Service and Information and Sales (Accts. 907 - 916) - Consumer Service and Information and Sales expenses are also considered consumer related expenses.

Administrative and General (Accts. 920 - 932) - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Thus, we have assigned 10 percent of these expenses to the power supply function and the remainder in proportion to the total of all other expenses without power supply.

Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the net plant account assignments.

Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the net plant account assignments.

Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.

Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense and return on equity, both related to plant investment, it is reasonable to classify this cost in proportion to the net plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., rate base - ROR method).

F. Allocation

The allocation of the revenue requirement to each consumer classification is presented in pages 20 to 22 of the COS. The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation

Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.

2. Consumer Costs Allocations

Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of the COS to recognize the higher cost of three phase service versus standard single phase service for each subcategory of consumer related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay at least a token portion of the consumer related expense, hence the 0.02 weighting factor.

3. Capacity Cost Allocations

Three different allocation factors were developed for the capacity component. (See pages 24 to 40 of the COS for the development of class demands):

   a. Line transformer capacity related costs were allocated in accordance with the estimated, undiversified non-coincidental annual peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

b. Distribution Substation and Primary line capacity costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased Power Demand Charges were allocated in accordance with the average monthly coincidental class demands established by season.

d. Purchased Power Transmission Charges were allocated in accordance with the average monthly coincidental class demands.

4. Energy Cost Allocations

Energy related costs were allocated on the basis of total energy sales in each rate class and further segmented into on-peak and off-peak energy.

Allocation factors for each category are developed in pages 41 to 42 of the COS.

3. Account Descriptions

Dakota Electric's distribution plant and expense amounts presented in the COS are organized according to the Uniform System of Accounts (USA). Following is a description of each account that is included in the COS.

A. Distribution Plant

Following is a description of the distribution plant accounts in the Uniform System of Accounts 360 to 373 for which Dakota Electric has plant recorded.

360 Land and Land Rights.
This account includes the cost of land and land rights used in connection with distribution operations.

361 Structures and Improvements.
This account includes the cost, in place, of structures and improvements used in connection with distribution operations.

362 Station Equipment.
This account includes the cost installed of station equipment, including transformer banks, which are used for the purpose of changing the characteristics of electricity in connection with its distribution.

364 Poles, Towers and Fixtures.

This account includes the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

365 Overhead Conductors and Devices.

This account includes the cost installed of overhead conductors and devices used for distribution purposes.

367 Underground Conductors and Devices.

This account includes the cost installed of underground conductors and devices used for distribution purposes.

368 Line Transformers.

This account includes the cost installed of overhead and underground distribution line transformers and pole-type and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

369 Services.

This account includes the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein.

370 Meters.

This account includes the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

373 Street Lighting and Signal Systems.

This account includes the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

B. General Plant

Following is a description of the general plant accounts in the Uniform System of Accounts 389 to 399 for which Dakota Electric has plant recorded.

389 Land and Land Rights.

This account includes the cost of land and land rights used for utility purposes, the cost of which is not properly includible in other land and land rights accounts.

390 Structures and Improvements.

This account includes the cost, in place, of structures and improvements used for utility purposes, the cost of which is not properly includible in other structures and improvements accounts.

391 Office Furniture and Equipment.

This account includes the cost of office furniture and equipment owned by the utility and devoted to utility service, and not permanently attached to buildings, except the cost of such furniture and equipment which the utility elects to assign to other plant accounts on a functional basis.

392 Transportation Equipment.

This account includes the cost of transportation vehicles used for utility purposes.

393 Stores Equipment.
This account includes the cost of equipment used for the receiving, shipping, handling, and storage of materials and supplies.
394 Tools, Shop and Garage Equipment.
This account includes the cost of tools, implements, and equipment used in construction, repair work, general shops and garages and not specifically provided for or includible in other accounts.
395 Laboratory Equipment.
This account includes the cost installed of laboratory equipment used for general laboratory purposes and not specifically provided for or includible in other departmental or functional plant accounts.
396 Power Operated Equipment.
This account includes the cost of power operated equipment used in construction or repair work exclusive of equipment includible in other accounts. Include, also, the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted.
397 Communication Equipment.
This account includes the cost installed of telephone and wireless equipment for general use in connection with utility operations.
398 Miscellaneous Equipment.
This account includes the cost of equipment, and apparatus used in the utility operations, which is not includible in other accounts.
399 Other Tangible Property.
This account includes the cost of tangible utility plant not provided for elsewhere.

C. Power Supply

Following is a description of the power supply account in the Uniform System of Accounts 555 for which Dakota Electric has expenses recorded.

555 Purchased Power.
This account includes the cost at point of receipt by the utility of electricity purchased for resale.

D. Transmission

Following is a description of the power supply account in the Uniform System of Accounts 555 for which Dakota Electric has transmission expense recorded.

555 Purchased Power.
This account includes the cost at point of receipt by the utility of electricity purchased for resale.

E. Distribution Expenses

Following is a description of the distribution accounts in the Uniform System of Accounts 580 to 598 for which Dakota Electric has expenses recorded.

581 Load Dispatching.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

582 Station Expenses.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in the operation of distribution substations.

583 Overhead Line Expenses.

584 Underground Line Expenses.
These accounts includes, respectively, the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in the operation of overhead and underground distribution lines.

586 Meter Expenses.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in the operation of customer meters and associated equipment.

587 Customer Installations Expenses.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in work on customer installations in inspecting premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

588 Miscellaneous Distribution Expenses.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in distribution system operation not provided for elsewhere.

590 Maintenance Supervision and Engineering.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, and expenses incurred in the general supervision and direction of maintenance of the distribution system. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account.

592 Maintenance of Station Equipment.
This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses

incurred in maintenance of plant, the book cost of which is includible in Account 362, Station Equipment, and Account 363, Storage Battery Equipment.

593 Maintenance of Overhead Lines.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in Account 364, Poles, Towers and Fixtures; Account 365, Overhead Conductors and Devices; and Account 369, Services.

595 Maintenance of Line Transformers.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in maintenance of distribution line transformers, the book cost of which is includible in Account 368, Line Transformers.

596 Maintenance of Street Lighting and Signal Systems.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in maintenance of plant, the book cost of which is includible in Account 373, Street Lighting and Signal Systems.

F. Consumer Accounting & Service

Following is a description of the consumer accounting accounts in the Uniform System of Accounts 901 to 905 for which Dakota Electric has expenses recorded.

902 Meter Reading Expenses.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in reading customer meters, and determining consumption when performed by employees engaged in reading meters.

903 Customer Records and Collection Expenses.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

904 Uncollectible Accounts.

This account is charged with amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits shall be made to Account 144, Accumulated Provision for Uncollectible Accounts - Credit. Losses from uncollectible accounts shall be charged to Account 144.

Following is a description of the consumer service and information accounts in the Uniform System of Accounts 907 to 910 for which Dakota Electric has expenses recorded.

908 Customer Assistance Expenses.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient, and economical use of the utility's service.

909 Informational and Instructional Advertising Expenses.

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

910 Miscellaneous Customer Service and Informational Expenses

This account includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred in connection with customer service and informational activities which are not includible in other customer information expense accounts.

G. Other

Following is a description of the administrative and general accounts in the Uniform System of Accounts 920 to 935 for which Dakota Electric has expenses recorded.

920 Administrative and General Salaries

This account includes the compensation (salaries, bonuses, employee pensions and benefits, social security and other payroll taxes, injuries and damages, and other consideration for services, but not including directors' fees) of officers, executives, and other employees of the utility properly chargeable to utility operations and not chargeable directly to a particular operating function.

921 Office Supplies and Expenses

This account includes office supplies and expenses incurred in connection with the general administration of the utility's operations which are assignable to specific administrative or general departments and are not specifically provided for in other accounts.

924 Property Insurance

This account includes the cost of insurance or reserve accruals to protect the utility against losses and damages to owned or leased property used in its utility operations.

925 Injuries and Damages

This account includes the cost of insurance or reserve accruals to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims.

926 Employee Pensions and Benefits

This account includes pensions paid to or on behalf of retired employees, or accruals to provide for pensions, or payments for the purchase of annuities for this purpose, when the utility has definitely, by contract, committed itself to a pension plan under which the pension funds are irrevocably devoted to pension purposes, and payments for employee accident, sickness, hospital, and death benefits, or insurance. Also included are expenses incurred in medical, educational or recreational activities for the benefit of employees, and administrative expenses in connection with employee pensions and benefits.

927 Franchise Requirements

This account includes payments to municipal or other governmental authorities, and the cost of materials, supplies and services furnished such authorities without reimbursement in compliance with franchise, ordinance, or similar requirements.

928 Regulatory Commission Expense

This account includes all expenses (except pay of regular employees only incidentally engaged in such work) properly includible in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions, or other regulatory bodies, or cases in which such a body is a party, including payments made to a regulatory commission for fees assessed against the utility for pay and expenses of such commission, its officers, agents, and employees.

930 Miscellaneous General Expenses

This account includes the cost of labor, materials used, and expenses incurred in advertising and related activities, the cost of which by their content and purpose are not provided for elsewhere.

935 Maintenance of General Plant

This account includes the cost assignable to customer accounts, sales and administrative and general functions of labor, materials used and expenses incurred in the maintenance of property, the book cost of which is includible in account 390, Structures and Improvements, account 391, Office Furniture and Equipment, account 397, Communication Equipment, and account 398 Miscellaneous Equipment.

Following is a description of the miscellaneous expense accounts in the Uniform System of Accounts 426 to 431 for which Dakota Electric has expenses recorded.

426.1 Donations

This account includes all payments or donations for charitable, social or community welfare purposes.

428 Amortization of Debt Discount and Expense

This account includes the amortization of unamortized debt discount and expense on outstanding long-term debt. Amounts charged to this account shall be credited concurrently to accounts 181, Unamortized Debt Expense, and 226, Unamortized Discount on Long-Term Debt—Debit.

429 Amortization of Premium on Debt

This account includes the amortization of unamortized net premium on outstanding long-term debt. Amounts credited to this account shall be charged concurrently to account 225, Unamortized Premium on Long-Term Debt.

431 Other Interest Expense

This account includes all interest charges not provided for elsewhere.

Following is a description of the depreciation expense accounts in the Uniform System of Accounts 403 to 407 for which Dakota Electric has expenses recorded.

403 Depreciation Expense
This account includes the amount of depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work.

Following is a description of the property expense account in the Uniform System of Accounts 408 for which Dakota Electric has expenses recorded.

408 Property & Other Taxes
These accounts includes the amounts of ad valorem, gross revenue or gross receipts taxes, state unemployment insurance, franchise taxes, Federal excise taxes, social security taxes, and all other taxes assessed by Federal, state, county, municipal, or other local governmental authorities, except income taxes.

Following is a description of the interest-long term account in the Uniform System of Accounts 427 for which Dakota Electric has expenses recorded.

427 Interest on Long-Term Debt
This account includes the amount of interest on outstanding long-term debt issued or assumed by the utility, the liability for which is included in account 221, Bonds, or account 224, Other Long-Term Debt

4. Classification

A. Distribution Plant

The classification of net distribution plant in service is shown on pages 4 and 5 of the COS. The classification of these plant accounts as capacity, consumer, or direct are as follows:

360 – Land – Classified as substation capacity related.
361 – Structures – Classified as substation capacity related.
362 – Station – Classified as substation capacity related.
364 – Poles – Classified as primary line capacity & consumer related.
365 – OH Conductor – Classified as primary line capacity & consumer related.
367 – UG Conductor – Classified as primary line capacity & consumer related.
368 – Transformers – Classified as line transformer capacity & consumer related.

369 – Services -- Classified as Secondary and Service consumer related.
370 – Meters – Classified as Meter consumer related.
371 – Cons Premise – Directly assigned to lighting.
373 – Street Light – Directly assigned to lighting.

Accounts 360, 361, and 362 are classified as capacity since they relate to substations. Substations are planned and built to meet the system demand requirements of the Cooperative.

Accounts 364, 365, 367, and 368 are each the subject of the minimum-size analysis and are classified as capacity and consumer related according to this analysis.

Accounts 369 and 370 are for distribution plant located at individual consumer sites and are classified as consumer related.

Accounts 371 and 373 are used for street lighting which is directly classified as lighting.

Each of these classifications are consistent with the classification of distribution plant as described on page 87 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

B. General Plant

The classification of net general plant in service is shown on pages 4 and 5 of the COS. The classification of general plant accounts as capacity, consumer, or direct follows the proportional classification of all distribution plant.

The classification of net general plant using the proportional classification of all other plant is based on the assumption that general plant supports the other plant functions. This approach to general plant classifications is consistent with the high level approach to classification of distribution plant as described on page 105 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

C. Power Supply

The classification of power supply expenses is shown on pages 8 through 13 of the COS. The classification of the above power supply expenses as energy or capacity follows the billing basis from our wholesale power supplier, Great River Energy (GRE).

Demand Charges - Summer	capacity
Demand Charges - Winter	capacity
Demand Charges - Other	capacity

Energy Charges – On-Peak	energy
Energy Charges – Off-Peak	energy

The classification of wholesale power supply costs follows the billing basis of our wholesale power supplier. Demand based charges are classified as capacity and energy based charges are classified as energy.

D. Transmission

The classification of transmission expense is shown on pages 8 through 13 of the COS. The classification of the transmission expenses as capacity follows the billing basis from our wholesale power supplier.

Transmission – G&T Charges	capacity

The classification of transmission costs follows the billing basis of our wholesale power supplier. The transmission demand based charge is classified as capacity.

E. Distribution Expenses

The classification of distribution expenses is shown on pages 8 through 13 of the COS. Distribution operation and maintenance expense into one or more of the following cost causative categories:

Substation – Capacity
Primary Line – Capacity
Primary Line – Consumer
Line Transformer – Capacity
Line Transformer – Consumer
Secondary & Service -- Consumer
Meter -- Consumer
Customer Accounting & Service – Consumer
Direct Assigned

The classification of the referenced accounts into the above categories is explained below.

581 – Load Dispatch - Classified based on classification of distribution operations accounts 582-587.
582 – Oper. Station –Classified to substation capacity-related.
583 – Oper. OH Line - Classified to primary line capacity & consumer related.
584 – Oper. UG Line – Classified to primary line capacity & consumer related.
586 – Oper. Meters – Classified to Meter – consumer related.
587 – Oper. Cons. Install - Classified to primary line capacity & consumer

related.
588 – Oper. Misc. Oper. Classified based on classification of distribution operations accounts 582-587.
590 – Main. Super. & Eng. - Classified based on classification of distribution maintenance accounts 591-596.
592 – Main. Station - Classified to substation capacity related.
593 – Main. OH Line – Classified as primary line capacity & consumer related.
595 – Main. Line Transf. - Classified as line transformer capacity & consumer related.
596 - Main. St. Lighting - Directly assigned to the lighting class.

Load dispatch expense in account 581 is classified into three categories of distribution substations, primary line, and meters and further into capacity and consumer related based upon the classification of other distribution operation expense accounts. These expenses are not directly related to one particular distribution category and so classifying based upon other assigned distribution operation expenses best reflects the nature of these expenses and the plant being operated/dispatched.

Operation expense associated with substations in account 582 is classified as substation capacity. This classification follows the classification of the plant being operated and for which these costs are incurred.

Operation expense associated with overhead and underground lines in accounts 583 and 584 is classified as capacity and consumer according to the minimum-size system classification approach applied to the plant accounts being operated and for which these costs are incurred.

Operation expense associated with meters in account 586 is classified as meter, consumer related. This classification follows the classification of the plant being operated and for which these costs are incurred.

Operation expense associated with consumer installations in account 587 is classified as capacity and consumer. This classification follows the classification of the primary line plant and for which these costs are incurred.

Miscellaneous operation expense in account 588 is classified into three categories of distribution substations, primary line, and meters and further into capacity and consumer related based upon the classification of other distribution operation expense accounts. These expenses are not directly related to one particular distribution plant category and so classifying based upon other assigned distribution operation expenses best reflects the nature of these expenses and the plant being operated.

Maintenance supervision and engineering expense in account 590 is classified into three categories of distribution substations, primary line, and line transformers and further into capacity and consumer related based upon the classification of other distribution maintenance expense accounts. These expenses are not directly related to one particular distribution plant category and so classifying based upon other assigned distribution maintenance expenses best reflects the nature of these supervision and engineering expenses.

Maintenance expense associated with substations in account 592 is classified as substation capacity related. This classification follows the classification of the plant being maintained and for which these costs are incurred.

Maintenance expense associated with overhead lines in account 593 is classified as primary line capacity and consumer related according to the minimum-size system classification approach applied to the plant accounts being maintained and for which these costs are incurred.

Maintenance expense associated with transformers in account 595 is classified as line transformer capacity and consumer related according to the minimum-size system classification approach applied to the plant accounts being maintained and for which these costs are incurred.

Maintenance expense associated with street lighting in account 596 is for street lighting which is directly classified as lighting.

Each of these classifications are consistent with the classification of distribution plant as described on page 87 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

F. Consumer Accounting & Service

The classification of distribution expenses is shown on pages 8 through 13 of the COS. Distribution expense accounts 902-904 are classified as Customer & Accounting and Service consumer related.

Meter reading expense in account 902 relates to the need to read individual consumer meters regardless of monthly energy or demand consumption. As such it has been classified as consumer related.

Records and collections expense in account 903 is classified as consumer. This classification relates to the need to maintain individual consumer records and bill consumers regardless of monthly energy or demand consumption.

Uncollectible accounts expense in account 904 is classified as consumer. This classification attributes uncollectible amounts as a general cost of doing business.

Each of these classifications are consistent with the classification of distribution plant as described on page 103 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

The classification of distribution expenses is shown on pages 8 through 13 of the COS. Distribution expense accounts 908-910 are classified as Customer & Accounting and Service consumer related.

Customer assistance expense in account 908 is classified as consumer. This classification relates to the need to provide information to individual consumers.

Information and instructional advertising expense in account 909 is classified as consumer. This classification relates to the need to provide information to consumers.

Miscellaneous customer service and informational expense in account 910 is classified as consumer. This classification relates to the need to provide information to consumers.

Each of these classifications are consistent with the classification of customer service and informational expenses as described on page 103 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

G. Other

The classification of distribution expenses is shown on pages 8 through 13 of the COS. The classification of the above distribution expenses as capacity, consumer, or direct are as follows:

920 to 932 – A&G Power Supply	energy & capacity
920 to 932 – A&G Distribution	capacity, consumer & direct
426 to 431 - Misc. Expenses Power Supply	energy & capacity
426 to 431 - Misc. Expenses Distribution	capacity, consumer & direct
403 – Depreciation Expense	capacity & consumer
408 – Property Taxes	capacity & consumer
427 – Interest on Long-Term Debt	capacity & consumer

Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Rather these expenses relate to supporting the overall operations of Dakota Electric. Therefore, A&G for power supply and distribution, along with miscellaneous expenses for power supply and distribution, are therefore classified in the same manner as other power supply and distribution expense classifications.

The depreciation, property taxes and interest on long-term debt expenses are classified in the same manner as distribution plant to which they are directly related.

5. Allocation

A. Distribution Plant

For convenience the responses to numbers 4 & 5 above are consolidated in the following. The cost causative categories along with their basis and reasoning for allocation are listed below.

Substation – Capacity related costs are allocated by each rate class' average and excess demand based upon the average monthly coincidental demand for each class (not necessarily coincident with the system). The average and excess demand allocator gives recognition to the average demand imposed on the system as well as the average monthly peak demand of the class (non-coincidental class demand).

Primary Line – Capacity related costs are allocated by each rate class' average and excess demand based upon the average monthly coincidental demand for each class (not necessarily coincident with the system). Distribution primary line capacity related costs are a function not only of the system peak but also the individual circuit and even consumer peak demand. The average and excess demand allocator gives recognition to the average demand imposed on the system as well as the average monthly peak demand of the class (non-coincidental class demand).

Primary Line – Consumer related costs are allocated based upon the weighted number of consumers in each rate class. The weighting factor assigned to each rate class can be seen in the COS, Page 41, Line 36. The weighting factors are developed on Page 23 of the COS and reflect the relative cost difference between the replacement costs for single vs. three phase primary line. Developing a weighting factor between single phase and three phase reflects cost causation because it takes into account the fact that the minimum-system three phase primary line costs more to install than the minimum-system single phase primary line.

Line Transformer – Capacity related costs are allocated based upon the sum of the individual customer annual peaks for each rate class. Line transformers are sized to meet the load requirements of each consumer in each class versus the system load. Allocating based upon the sum of each consumer's annual peak demand by class therefore best reflects cost causation.

Line Transformer – Consumer related costs are allocated based upon the weighted number of consumers in each rate class. The weighting factor assigned to each rate class can be seen on Page 41, Line 38 of the COS. The weighting factors are developed on Page 23 of the COS and reflect the relative cost difference between the replacement costs for a single phase versus three phase line transformer.

Secondary & Services – Consumer related costs are allocated based upon the weighted number of consumers in each rate class. The weighting factor assigned to each rate class can be seen on the COS, Page 41, Line 40. The weighting factors are develop on the COS, Page 23 and reflect the relative cost difference between the replacement costs for single phase versus three phase secondary and service facilities.

Meter – Consumer related costs are allocated based upon the weighted number of consumers in each rate class. The weighting factor assigned to each rate class can be seen on the COS, Page 41, Line 42. The weighting factors are developed on page 23 and reflect the relative cost difference between the replacement costs for single phase versus three phase and between kWh vs. kW meters as appropriate.

Accounting & Service – Consumer related costs are allocated based upon the weighted number of consumers in each rate class. The weighting factor assigned to each rate class is the same as the meter weighting factor.
Direct – Investment in lighting systems which are recorded to plant account no. 373 have been direct assigned/allocated to the lighting rate class.

For details on the consumer weighting and allocation factors please reference the COS, Pages 23 and 41-42 respectively. For details on the capacity allocation factors please reference the COS, Pages 24 to 42.

B. General Plant

The allocation of plant in service is shown on page 19 of the COS. The allocation of general plant accounts follows the proportional allocation of all distribution plant.

The allocation of general plant using the proportional classification of all other plant is based on the assumption that general plant supports the other plant functions. This approach to general plant allocations is consistent with the high level approach to allocation of distribution plant as described on page 105 of the NARUC "Electric Utility Cost Allocation Manual" published in January 1992.

C. Power Supply

The allocation of power supply expenses is shown on pages 20 through 22 of the COS. The allocation of these power supply accounts is as follows:

Demand Charges – Summer – Summer capacity costs are allocated based upon each rate classification's estimated contribution to the Cooperative's purchased power summer billing demand (average summer month). Dakota Electric is billed for summer capacity from GRE based upon its contribution to the GRE coincident peaks for the months of June, July and August.

Allocating purchased power summer demand charges based upon each rate classification's contribution to the summer demand billing peaks therefore reflects the principle of cost causation.

Demand Charges – Winter – See response above for the winter months of December, January and February.

Demand Charges – Other – See response above for the spring and fall months of March-May and September-November.

Energy Charges – On-Peak – On-peak energy costs are allocated to each rate classification based upon the estimated on-peak energy purchases made to serve the rate class. Allocating these costs on the basis of each rate classification's on-peak energy requirements therefore reflects the principle of cost causation.

Energy Charges – Off-Peak – Off-peak energy costs are allocated to each rate classification based upon the estimated off-peak energy purchases made to serve the rate class. Allocating these costs on the basis of each rate classification's off-peak energy requirements therefore reflects the principle of cost causation.

D. Transmission

The allocation of transmission expense is shown on pages 20 through 22 of the COS. The allocation of the transmission account is as follows:

Transmission – G&T Charges – Allocated based upon each rate classification's contribution to the transmission billing peaks as defined as the GRE monthly coincident peaks.

Dakota's transmission costs are based upon the GRE transmission rate which is the same throughout the year and is based upon the contributions to each months' coincident peak demand. The average monthly CP demand by rate class is therefore used to allocate these wholesale power costs which is consistent with cost causation.

E. Distribution Expenses

Please reference the response to Information Request No. 705, part 4 which identifies and describes the allocation factors used for each cost causative category. As identified in the above number 2, the following cost causative categories are used for the classification of distribution operation and maintenance expenses.

Substation – Capacity
Primary Line – Capacity

Primary Line – Consumer
Line Transformer – Capacity
Line Transformer – Consumer
Secondary & Service -- Consumer
Meter -- Consumer
Customer Accounting & Service – Consumer
Direct Assigned

F. Consumer Accounting & Service

The allocation of distribution expenses is shown on pages 20 through 22 of the COS. The allocation of Customer Accounting and Service consumer related costs is based on the weighted number of customers for each rate class. The weighting factor assigned to each rate class can be seen on the COS, Page 41, Line 42. The weighting factors are develop on page 23 and reflect the relative cost difference between the replacement costs for single phase versus three phase and between kWh vs. kW meters as appropriate.

Because these expenses are related to the number of consumers rather than capacity or energy requirements, these costs have been allocated based upon the number of consumers. To account for complexity and additional data requirements, different weighting factors have been applied based upon different meter types.

The allocation of distribution expenses is shown on pages 20 through 22 of the COS. The allocation of Customer Accounting and Service consumer related costs is based on the weighted number of customers for each rate class. The weighting factor assigned to each rate class can be seen on the COS, Page 41, Line 42. The weighting factors are develop on page 23 and reflect the relative cost difference between the replacement costs for single phase versus three phase and between kWh vs. kW meters as appropriate to represent complexity.

Because these expenses are related to the number of consumers rather than capacity or energy requirements, these costs have been allocated based upon the number of consumers. These costs however are not evenly distributed between all consumers or between all rate classes. To reflect this reality, the number of consumers has been weighted as described in number 4 above so that more complex rates, meters and consumers receive a greater weight of these costs on a per consumer basis.

G. Other

For the allocation method for each cost causative category please reference:

Power Supply – Part 4 of Information Request No. 707.
Distribution – Part 4 of Information Request No. 705.

For the reasoning behind the allocation methods used for each cost causative category please reference:

Power Supply – Part 4 of Information Request No. 707.
Distribution – Part 4 of Information Request No. 705.

6. Summary of COS Results

The results of the COS are summarized on pages 1 to 3 of the study. The first page shows the revenue requirement for each class, the revenue from present rates, and the required increase or decrease in revenue on a dollar and percentage basis for revenue to equal the COS results. The second page shows the costs allocated to major components including power supply, transmission, and distribution. Finally, the third page presents the information from page 2 on a cents per kWh or $ per month per consumer basis.

7. References

Relevant reference material includes:

The National Association of Regulatory Utility Commissioners (NARUC) "Electric Utility Cost Allocation Manual", January 1992.

Rural Utilities Service (RUS) "Uniform System of Accounts", Bulletin 1767B-1.

Workpaper 21
Minimum Size Method

Dakota Electric Association
General Rate Case
E-111/GR-19-478

Minimum-Size Method w/ Demand Adjustment
Workpaper #21

Customer and Demand Classification of Distribution Plant Accounts

Introduction

In the Commission's final Order in Dakota Electric's 2009 General Rate Case in Docket No. E-111/GR-09-175, Ordering Paragraph #6 requires that:

> *Dakota Electric shall, in its next rate case, either use the minimum-size method to classify Distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method.*

This narrative will 1) provide an overview of this issue as described in the NARUC Manual, 2) describe the analysis and results to identify the demand adjustment to the Minimum-Size analysis, 3) review Dakota Electric's Minimum-Size analysis with the demand adjustment and results, and 4) compare the Minimum-Size analysis results with the Zero-Intercept classification method.

NARUC Overview of Distribution Plant Classification

The National Association of Regulatory Utility Commissioners (NARUC) publication "Electric Utility Cost Allocation Manual" (NARUC Manual) provides a comprehensive overview of issues and methods used in cost of service studies for electric utilities. Regarding the classification of distribution plant, two methods in common use for classifying distribution plant as "customer" and "demand" are the Minimum-Size Method and the Minimum-Intercept (or Zero-Intercept) Method. Since being rate-regulated by the Minnesota Public Utilities Commission (MPUC or Commission) in 1981, every general rate case filed by Dakota Electric Association (Dakota Electric or Cooperative) has used the Zero-Intercept Method to classify distribution plant into customer and demand components. Once classified, the associated distribution plant costs are then allocated to various rate classes based on accepted allocation factors.

Following are relevant excerpts taken from portions of pages 90 through 95 of the January 1992 NARUC publication "Electric Utility Cost Allocation Manual" regarding the classification of distribution plant:

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand-and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of

> *demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.*
>
> *Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.*

Demand Adjustment

<u>Introduction</u>

In the Commission's final Order in Dakota Electric's 2014 General Rate Case in Docket No. E-111/GR-14-482, the Commission made the following observation on Page 16 regarding the minimum system analysis used in the class cost of service study:

> *The Commission concurs with the Department that a demand adjustment would be a reasonable refinement to the minimum system analysis in the Cooperative's next rate case and will require that it include one. As the Department's witness noted, the minimum-size method can intrinsically include some demand-related costs associated with the load carrying capability of the equipment included in the study, and it is important to isolate demand costs as accurately as possible.*

To this end, the Commission's Ordering Paragraph #8 requires that:

> *Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.*

This narrative describes the process used to study the amount of demand that a Dakota Electric "Minimum System" could support. A Minimum System is one that assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the consumer. The question is what load could this Minimum System supply? This study has been developed to provide an answer to that question.

<u>System Modelling</u>

The Cooperative's planning and operational model of the existing distribution system was used as a starting point for this study. The existing distribution system model includes all the lines and equipment that are installed to supply power to Dakota Electric members. The base model is a representation of the electrical system configuration which is used to supply the members. This same base model is used to study the electrical system's ability to support member electrical demands.

To create a Minimum System model from the base model, we converted the model from the existing distribution system lines and equipment to a Minimum System. A Minimum System uses the smallest underground wire which is a single-phase #2 conductor and the smallest overhead wire which is a single-phase #4 ACSR overhead wire. Also, all of the transformers in a Minimum System model are single-phase 10kVA units. The base model for the existing system includes conductors and transformers that are larger than the Minimum System. To create the Minimum System model, all of the three phase lines were converted to single phase and the conductor sizes were changed to minimum conductor sizes. The transformers were also changed to be single-phase 10kVA units. All of the member loads were also converted to single phase loads to match up with the single-phase model.

The following scenarios have been developed to model member loads on each of the feeders and evaluate the amount of load that can be supplied with a Minimum System:

1. 1 kW per feeder with load growth percentages applied;
2. 100 kW and 500 kW per feeder options;
3. 200 kW per feeder; and
4. 200 kW per feeder and then increasing load on individual substations.

These scenarios were developed in a stepwise fashion to hone in on a solution /answer to the question of how much load can be served by the Minimum System.

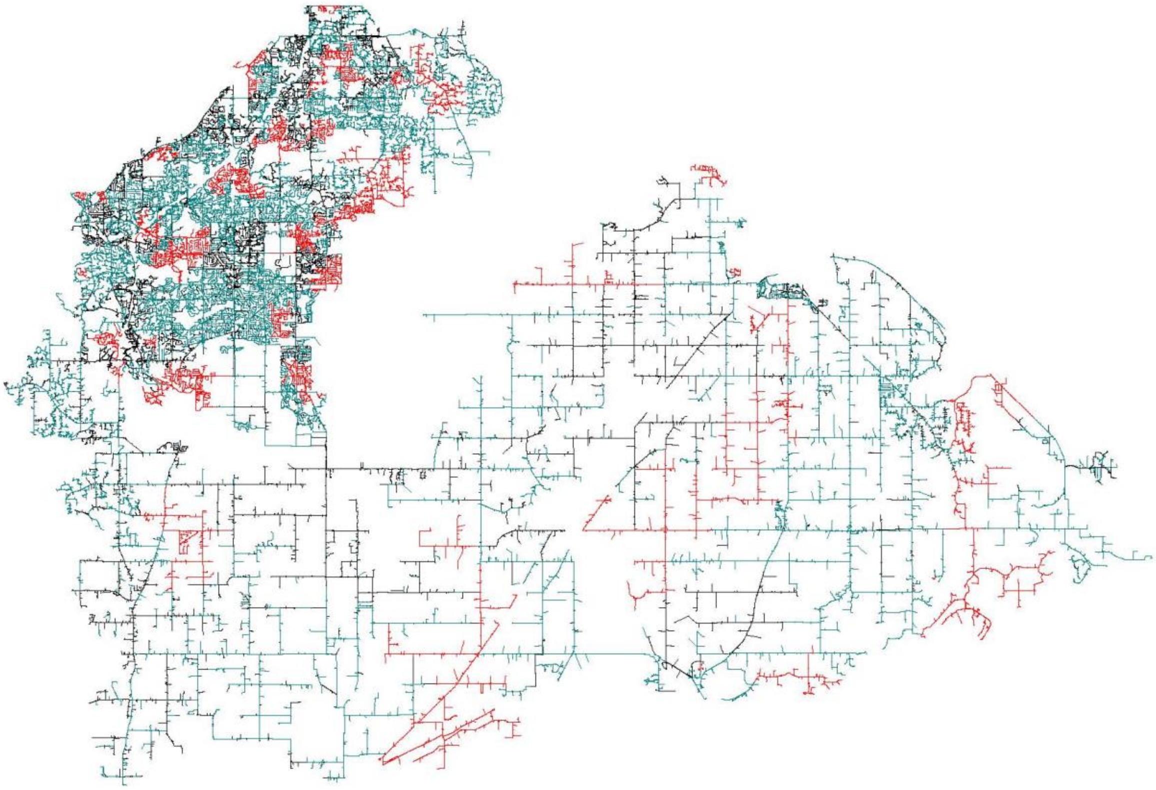
Scenario #1

The first scenario set 1 kVA at the feeder source and this value was then allocated to all of the services connected to the feeder downstream of the source. The initial model did not include the 10kVA distribution transformers in an attempt to simplify the solution, so each of the services was directly connected to the primary circuits. The allocation was based upon the historical kWh usage of each of the services. Using the allocated load, the total load on each of the substations was then increased until the voltage drop on the substation was above a normal design level at several locations. For operational and planning studies on the Dakota Electric system, the voltage at the source of the substation and feeder is set at 124 volts and if any portion of the feeder is below 118 volts then that solution exceeds the tolerance for a normal system configuration. This first scenario resulted in a solution that had very high var[1] flow and thus impacted the voltage drop on many of the feeders and resulted in a low amount of load which could be supported by the system. The following picture (Figure 1) shows the Dakota Electric system. The areas in red are where the voltage was calculated to be below operational and planning levels.

For this version of the model, the total system load was 12,881 kW which was reached by increasing the load from the initial 1 kW per feeder by a load growth percentage. In many cases this load growth percentage was 1,000 or more. Simply multiplying the loads, resulted in very large var demands from some of the loads and appears to result in a more significant voltage drop on the system. Thus, limiting the amount of power which could be supported by the Minimum System. This version of the model has 12,881 kW supplied by the feeders, with 8,532 kW of system losses. So, the total load <u>actually</u> being supplied by this version of the model is 4,349 kW. The solution is supported by 116,164 kVARs coming from the transmission system.

[1] **volt-ampere reactive** (**var**) is a unit by which reactive power is expressed in an AC electric power system. Since reactive power does not do any real work, the extra current supplied to provide the reactive power means greater line losses and higher thermal limits for equipment.

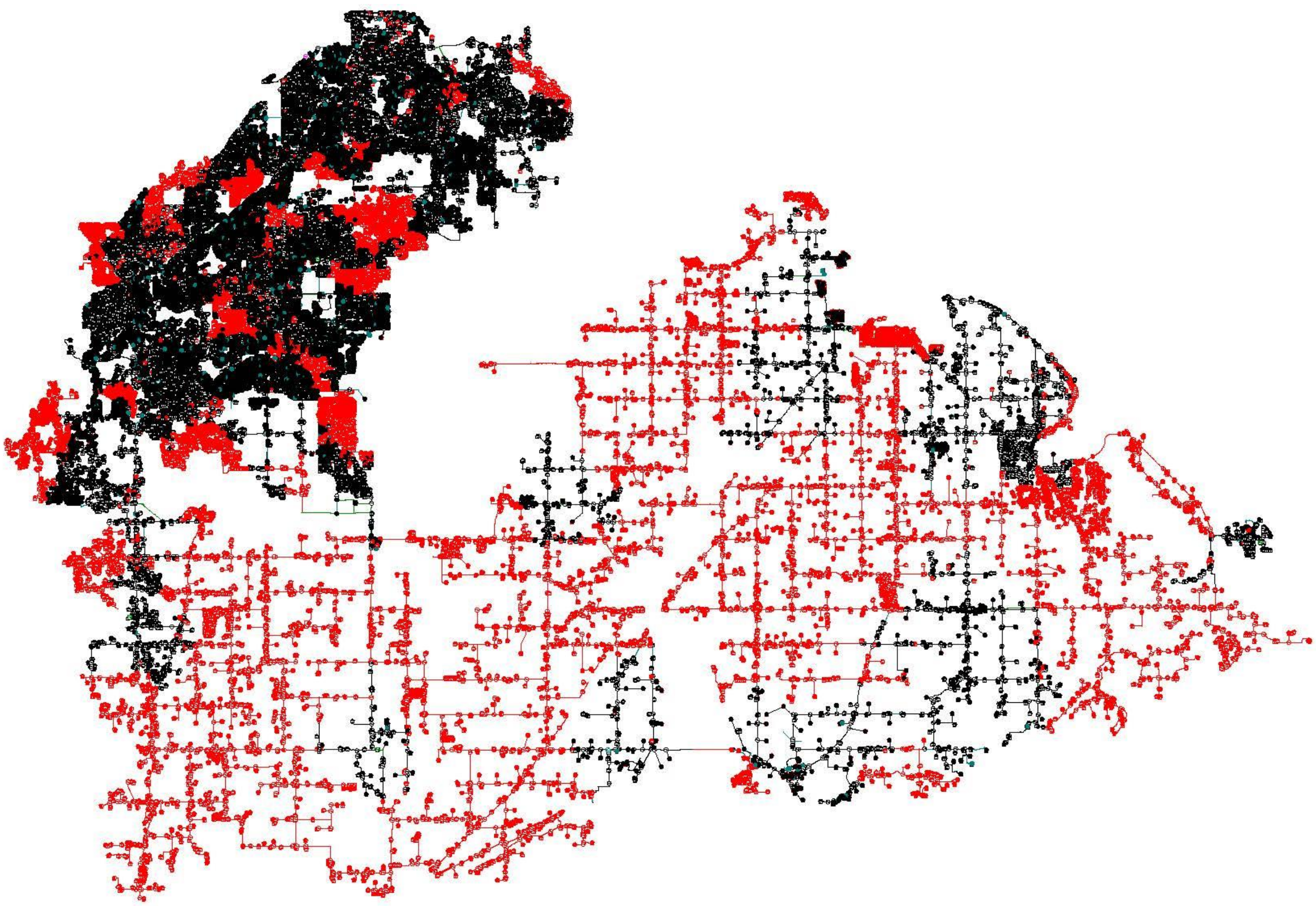
Figure 1.



Scenario #2

To improve the solution, the model was rebuilt and the 10kVA distribution transformers were included and each of the services were connected to the secondary of the transformers. The load allocation followed the same allocation methods and was redone in Scenario #2 using 100 and 500 kW values, instead of the 1 kW per feeder value. The 100 kW per feeder resulted in very few voltage violations, but the 500 kW allocation resulted in many voltage violations throughout the system as shown by the red areas in the following picture (Figure 2).

Figure 2.

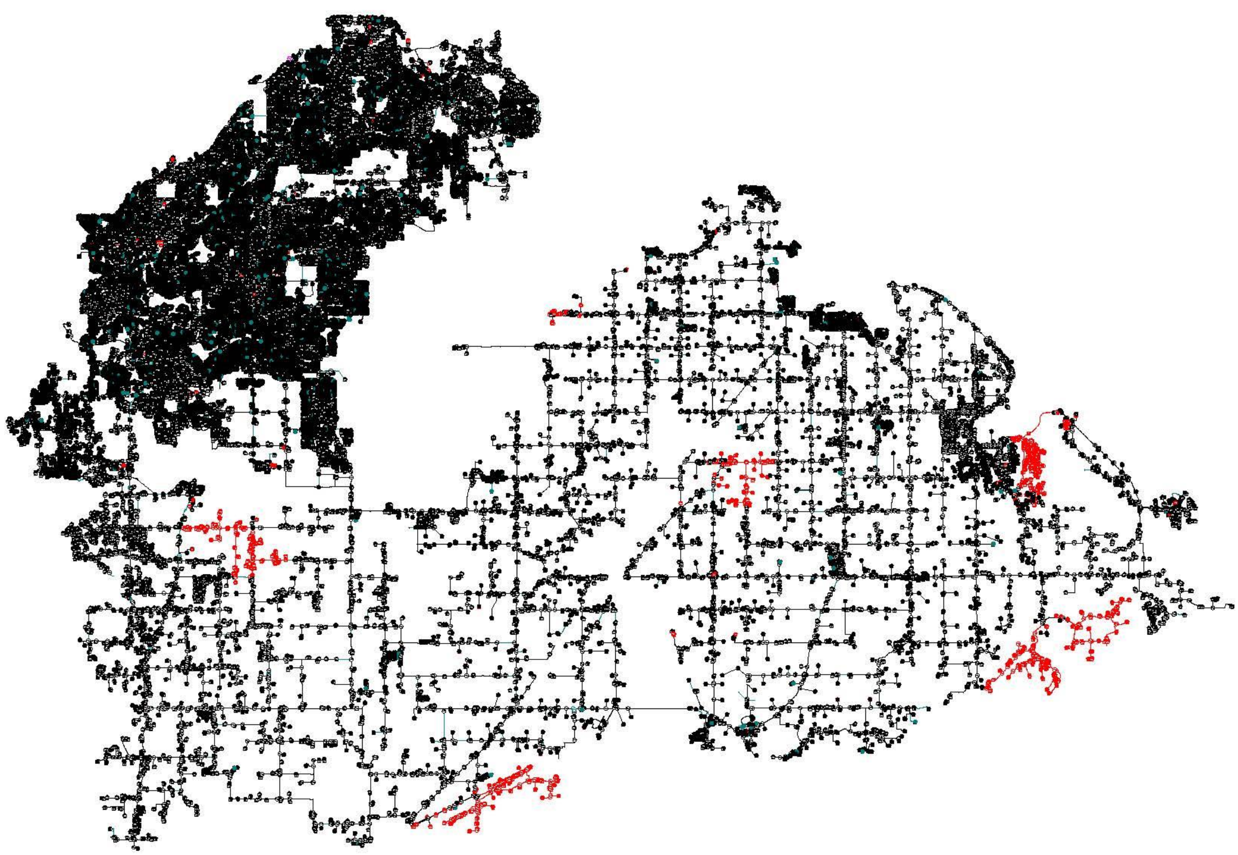


Scenario #3

Given the Scenario #2 results from the 100 kW and 500 kW allocation solutions, 200 kW was next selected to be applied to each of the feeders in Scenario #3 and then allocating that over the existing services. This allocation resulted in a base minimum system model which had a good balance between few if any voltage violations and too many voltage violations. The voltage results for Scenario #3, as shown in the following picture (Figure 3) show the voltage violations in red and appeared to be a reasonable basis for continued analysis. At this point the model has 33,998 kW being supplied by the feeders, with 904 kW in loses. So, the total load on this model is 33,095 kW. This version of the model required 6,819 kVAR support from the transmission system.

One could consider this the total load for this model that the Minimum System could support. For some of the substations, this is actually above the load which the Minimum System could support, but for other substations this is below the level that the substation could support.

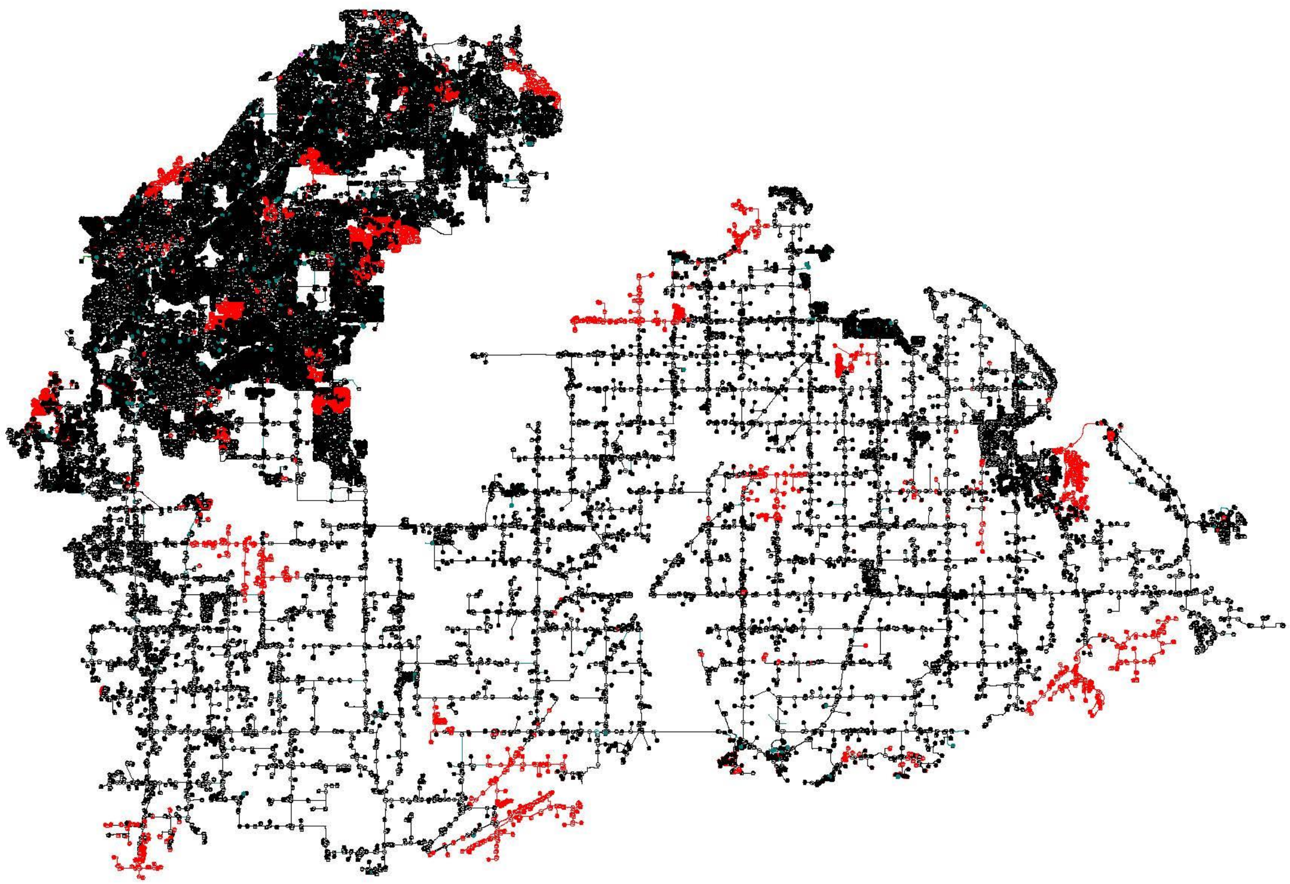
Figure 3.



Scenario #4

Using the Scenario #3 version of the model, shown in Figure 3, we looked at how best to add more load to the model. To accomplish this, the load on each of the substations was individually raised in Scenario #4 to identify the load level where that substation reached a point where the voltage to the services could not be maintained at the operational and planning levels. This version of the model, Figure 4, reflects 63,788 kW on the feeders which includes 3,303 in system kW loss. So, the resulting load supported by this system is 60,485 kW. It is important to note that, for this version of the model to solve, the solution required 21,502 in kVAR support from the transmission system.

Figure 4.



The resulting value of load supported by the model in this study is variable as one can see from the red areas in Figure 4. The load levels are above what can be supported by the Minimum System in some of the areas. Even with the version of the model in Figure 3 some of the areas are overloaded, but many areas are not. More importantly, the Figure 4 solution has significant voltage support from the transmission system in the form of over 21 MVARs.

Vars and Power Factor

The two primary factors affecting the voltage drop from the source to the load are the impedance between the source and the load, and the power factor of the load. The different versions of the models used for this study reflect the impedance between the source and load and that is a fixed value for all of the solutions. The power factor for each of the loads was also fixed in the models used for Scenarios 2, 3 and 4. The residential loads were fixed at 98% and the commercial loads were fixed at 92% lagging for the power factor, which are typical observed values for these classes. The lower the power factor the greater the voltage drop between the source and load.

To support the additional vars required by the load as it was grown and to support the additional vars consumed by the distribution system from transporting the additional power, additional var support was required to be supplied by the source, which represents the distribution substation and transmission system. Without the significant var support from the sources the model would not mathematically converge.

The voltage support in the Dakota Electric distribution system is supplied by voltage regulation and capacitors. Voltage regulation is provided at each of the substations and in a few areas at places along the feeders. Capacitors are installed along the feeders to provide var support for the loads.

Demand Adjustment Summary

Based on the results from this study, the maximum system load that the Minimum System can support is likely more than 33 MWs (Figure 3) and less than 60 MWs (Figure 4). At these system loading levels, a significant number of feeders have exceeded the voltage tolerance for a normal system configuration and rely heavily on var support from the transmission system. Dakota Electric has applied the higher end of this system loading range (60,485 kW) in the Minimum-Size Method by calculating the installed cost of the capacity that is provided for each account where applicable (there is no capacity component for poles) and subtracting this capacity value from the consumer component. The result is a demand adjusted consumer component (dollars and percentage) for each account that was applied in the cost of service study.

Minimum-Size Method

The NARUC manual describes the approach to the Minimum-Size Method as follows:

> *Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other*

methods show that it generally produces a larger customer component than the zero-intercept method ...

Dakota Electric's calculation of the demand adjusted Minimum-Size Method is shown on page 12 of this workpaper. As described above from the NARUC Manual, Dakota Electric's calculations are made using the average book cost for the minimum size of each piece of equipment presently being installed. We have also incorporated a demand adjustment to the Minimum-Size method as determined above and described below. Following is a summary of the demand-adjusted calculations for Account 364 (Poles, Towers, and Fixtures), Account 365 (Overhead Conductors and Devices), Account 367 (Underground Conductors and Devices), and Account 368 (Line Transformers).

Account 364 (Poles, Towers, and Fixtures):

- The minimum size pole installed on Dakota Electric's system is a 35 foot Class 5 pole.
- The average book cost for the minimum size pole is $189.87.
- There are 28,600 total poles on the Dakota Electric system.
- Multiplying the average book cost for the minimum size pole times the total number of poles results in a minimum cost of $5,430,365.
- The installed book cost of all poles is $12,343,021.
- There is no demand component for a pole.
- Dividing the minimum cost by the installed book cost results in a 44.00% consumer classification of the installed book cost of poles.

Account 365 (Overhead Conductors and Devices):

- The minimum size overhead conductor installed on Dakota Electric's system is #4 ACSR.
- The average book cost for the minimum size overhead conductor is $0.14438 per foot.
- There are 17,745,702 total feet of overhead conductors on the Dakota Electric system.
- Multiplying the average book cost for the minimum size overhead conductor times the total number of feet results in a minimum cost of $2,562,054.
- The demand adjustment to the minimum cost of overhead conductors is $1,090,347.
- The demand adjusted minimum cost of overhead conductors is $1,471,707.
- The installed book cost of all overhead conductors is $8,908,099.
- Dividing the demand adjusted minimum cost by the installed book cost results in a 16.52% adjusted consumer classification of the installed book cost of overhead conductors.

Account 367 (Underground Conductors and Devices):

- The minimum size underground conductor installed on Dakota Electric's system is #2 URD.
- The average book cost for the minimum size underground conductor is $2.7457 per foot.
- There are 25,478,084 total feet of underground conductors on the Dakota Electric system.
- Multiplying the average book cost for the minimum size underground conductor times the total number of feet results in a minimum cost of $69,956,247.
- The demand adjustment to the minimum cost of underground conductors is $3,266,556.

- The demand adjusted minimum cost of overhead conductors is $66,689,691.
- The installed book cost of all underground conductors is $88,968,269.
- Dividing the demand adjusted minimum cost by the installed book cost results in a 74.96% adjusted consumer classification of the installed book cost of underground conductors.

Account 368 (Line Transformers):

- The minimum size transformer installed on Dakota Electric's system is 10 kVA single phase overhead.
- The average book cost for the minimum size transformer is $441.21.
- There are 22,940 total transformers on the Dakota Electric system.
- Multiplying the average book cost for the minimum size transformer times the total number of transformers results in a minimum cost of $10,121,249.
- The demand adjustment to the minimum cost of transformers is $3,944,399.
- The demand adjusted minimum cost of transformers is $6,176,851.
- The installed book cost of all transformers is $33,078,453.
- Dividing the demand adjusted minimum cost by the installed book cost results in a 18.67% adjusted consumer classification of the installed book cost of transformers.

Comparison of Results

Following is a comparison of the cost of service (COS) study results using the demand-adjusted minimum-size method as ordered by the Commission compared to using the zero-intercept method:

Method	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
Minimum-Size	5.29%	8.94%	-2.72%	-0.26%	7.98%	18.79%
Zero-Intercept	4.72%	8.18%	-1.46%	0.45%	9.21%	18.98%

Dakota Electric Association
Minimum-Size Method (CPR Records)
Docket No. E-111/GR-19-478

NARUC - Electric Utility Cost Allocation Manual (January 1992)
Minimum Size Methodology for Determining Consumer Cost

1. Account 364 - Poles, Towers, and Fixtures

35 foot Class 5 Pole

				Method	Demand Adjustment		
	$	189.87	Average Unit Cost of Minimum Pole	1. Determine the average installed book cost of the minimum height pole currently being installed.	$	189.87	No demand adjustment applied
x		28,600	Total Poles	2. Multiply the average book cost by the number of poles to find the customer component.		28,600	
=	$	5,430,365	Subtotal		$	5,430,365	
÷	$	12,343,021	Installed Book Cost - Poles		$	12,343,021	
=		44.00%	Consumer Component			44.00%	Consumer Component

2. Account 365 - Overhead Conductors and Devices

#4 ACSR

				Method			
	$	0.14438	Average Unit Cost of Minimum OH Conductor	1. Determine the minimum size conductor currently being installed.	$	6,346,044	Unadjusted installed cost - capacity
x		17,745,702	Total Feet OH Conductor	2. Multiply the average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component.		352,035	kW system peak load less minimum system load
=	$	2,562,054	Subtotal		$	18.03	Adjusted installed cost per kW
÷	$	8,908,099	Installed Book Cost - OH Conductor			60,485	kW minimum system load
=		28.76%	Consumer Component	(Note: DEA cost and analysis is on a per foot basis.)	$	1,090,347	Installed cost to be removed from minimum system cost
					$	1,471,707	Adjusted minimum system cost
						16.52%	Adjusted Consumer Component

3. Account 367 - Underground Conductors and Devices

#2 URD

				Method			
	$	2.7457	Average Unit Cost of Minimum URD Conductor	1. Determine the minimum size cable currently being installed.	$	19,012,022	Unadjusted installed cost - capacity
x		25,478,084	Total Feet URD Conductor	2. Multiply the average installed book cost per mile of minimum size cable by the number of circuit miles to determine the customer component.		352,035	kW system peak load less minimum system load
=	$	69,956,247	Subtotal		$	54.01	Adjusted installed cost per kW
÷	$	88,968,269	Installed Book Cost - URD Conductor			60,485	kW minimum system load
=		78.63%	Consumer Component	(Note: DEA cost and analysis is on a per foot basis.)	$	3,266,556	Installed cost to be removed from minimum system cost
					$	66,689,691	Adjusted minimum system cost
						74.96%	Adjusted Consumer Component

4. Account 368 - Line Transformers

10 kVA Single Phase Overhead

				Method			
	$	441.21	Average Unit Cost of Minimum Transformer	1. Determine the minimum size transformer currently being installed.	$	22,957,203	Unadjusted installed cost - capacity
x		22,940	Total Transformers	2. Multiply the average installed book cost of minimum size transformer by the number of transformers in plant account to determine the customer component.		352,035	kW system peak load less minimum system load
=	$	10,121,249	Subtotal		$	65.21	Adjusted installed cost per kW
÷	$	33,078,453	Installed Book Cost - Transformers			60,485	kW minimum system load
=		30.60%	Consumer Component		$	3,944,399	Installed cost to be removed from minimum system cost
					$	6,176,851	Adjusted minimum system cost
						18.67%	Adjusted Consumer Component

61.5%	Wgtd Minimum Size	**55.7%**	**Capacity Adjusted Wgtd Minimum Size**

Dakota Electric Association
Minimum-Size Method (CPR Records)
Docket No. E-111/GR-19-478

Poles - Acct 364

Description	*Units*		*Cost*		*Avg Unit Cost*
35 and under	13,439	$	2,551,701.75	**$**	**189.87**
40 and 45	14,687	$	9,323,737.94	$	634.83
50 and over	474	$	467,581.79	$	986.46
	28,600	$	12,343,021		

Dakota Electric Association
Minimum-Size Method (CPR Records)
Docket No. E-111/GR-19-478

Overhead Conductors - Acct 365

Description	***Units***		***Cost***		***Avg Unit Cost***
477 MCM ACSR	1,878,162	$	2,995,222.95	$	1.59476
336 MCM ACSR	448,062	$	345,431.74	$	0.77095
1/0 ACSR	2,035,195	$	869,664.40	$	0.42731
4/0 ACSR	2,919,516	$	1,847,878	$	0.63294
2 ACSR	626,574	$	75,572.99	$	0.12061
4 ACSR	8,339,814	$	1,204,069.46	**$**	**0.14438**
1/0 OR 2/0 OH Secondary	728,790	$	819,198.00	$	1.12405
3/0, 4/0 or Larger OH Secondary	53,715	$	148,062.62	$	2.75645
#2 #4 #6 & Smaller OH Secondary	715,874	$	602,998.87	$	0.84233
	17,745,702	$	8,908,099		

Dakota Electric Association
Minimum-Size Method (CPR Records)
Docket No. E-111/GR-19-478

Underground Conductors - Acct 367

Description	***Units***		***Cost***	***Avg Unit Cost***	
6 Secondary URD	2,205,804	$	2,132,806.11	$	0.96691
1/0 Secondary URD	1,245,809	$	1,734,714.87	$	1.39244
4/0 Secondary URD	1,661,581	$	3,251,570.11	$	1.95691
2 Primary URD	9,053,704	$	24,859,135.99	**$**	**2.74574**
1/0 Primary URD	6,004,252	$	20,744,486.57	$	3.45497
4/0 Primary URD	539,303	$	2,000,175.68	$	3.70882
500 Primary URD	3,681,738	$	25,298,701.41	$	6.87140
350 secondary URD	84,933	$	337,170.36	$	3.96984
3/0 Secondary URD	2,041	$	2,965.15	$	1.45279
750 Primary URD	998,919	$	8,606,542.80	$	8.61586
	25,478,084	$	88,968,269		

Dakota Electric Association
Minimum-Size Method (CPR Records)
Docket No. E-111/GR-19-478

Line Transformers - Acct 368

Description	*Units*		*Cost*		*Avg Unit Cost*
1 KVA 1PH OH	99	$	51,845.42	$	523.69
3 KVA 1PH OH	-	$	-	$	-
5 KVA 1PH OH	90	$	11,763.83	$	130.71
7.5 KVA 1PH OH	172	$	27,424.54	$	159.45
10 KVA 1PH OH	2,888	$	1,274,200.88	**$**	**441.21**
10 KVA 1PH PADMT	929	$	629,943.27	$	678.09
15 KVA 1PH OH	1,370	$	757,281.60	$	552.76
15 KVA 1PH PADMT	2,602	$	2,981,820.01	$	1,145.97
1.5 KVA 1PH OH	154	$	235,156.84	$	1,526.99
25 KVA 1PH OH	1,264	$	864,439.47	$	683.89
25 KVA 1PH PADMT	3,640	$	3,525,152.81	$	968.45
37.5 KVA 1PH OH	405	$	347,741.60	$	858.62
37.5 KVA 1PH PADMT	4,062	$	4,592,076.15	$	1,130.50
45 KVA 3PH PADMT	32	$	154,010.66	$	4,812.83
50 KVA 1PH OH	144	$	185,130.62	$	1,285.63
50 KVA 1PH PADMT	2,851	$	3,598,389.95	$	1,262.15
75 KVA 1PH OH	30	$	77,010.79	$	2,567.03
75 KVA 1PH PADMT	228	$	497,679.04	$	2,182.80
100 KVA 1PH OH	17	$	19,236	$	1,131.51
100 KVA 1PH PADMT	16	$	33,152.95	$	2,072.06
112.5 KVA 3PH PADMT	478	$	2,121,184.05	$	4,437.62
150 KVA 3PH PADMT	283	$	1,505,784.58	$	5,320.79
167 KVA 1PH OH	6	$	10,123.37	$	1,687.23
167 KVA 1PH PADMT	20	$	43,592.37	$	2,179.62
225 KVA 3PH PADMT	178	$	1,214,119.37	$	6,820.90
300 KVA 3PH PADMT	185	$	1,422,502	$	7,689.20
500 KVA 3PH PADMT	134	$	1,616,327.81	$	12,062.15
750 KVA 3PH PADMT	44	$	625,071.33	$	14,206.17
1000 KVA 3PH PADMT	41	$	770,806.26	$	18,800.15
1500 KVA 3PH PADMT	59	$	1,420,691.59	$	24,079.52
2000 KVA 3PH PADMT	4	$	269,116.31	$	67,279.08
DUPLEX 250/37.5 KVA PADMT	-	$	-	$	-
DUPLEX 333/25 KVA PADMT	-	$	-	$	-
DUPLEX 75/25 KVA PADMT	-	$	-	$	-
DUPLEX 167/25 KVA PADMT	-	$	-	$	-
75 KVA 3PH PADMT	515	$	2,195,677	$	4,263.45
Total	22,940	$	33,078,453		
50 KVA and less	20,702	$	19,236,378		

Workpaper 20
Organizational Dues

Dakota Electric Association
Summary of Dues and Memberships
2018

ORGANIZATION	PROJECT	AMOUNT	DATE	DESCRIPTION/EMPLOYEE	*PURPOSE
AFCOM	ECO	$ 299	7/31/2018	7/2018-2019 MEMBR-M LOFTHUS	B
AMERICAN PAYROLL ASSOCIATION	PAY	219	6/30/2018	2018 APA RENEW/160557	B
APPLE VALLEY CHAMBER OF COMM	COMMREL	952	1/31/2018	2018 DUES-P JOHNSON	A
ASSN OF ENERGY ENGINEERS	ACS	215	1/31/2018	EXPENSE REPORT - JANE SIEBENALER	B
ASSN OF ENERGY ENGINEERS	ACS	215	12/31/2018	EXPENSE REPORT - JANE SIEBENALER	B
ASSOCIATION OF ENERGY ENGINEERS	KEY	195	9/30/2018	EXPENSE REPORT - DAN ROSS	B
ASSOCIATION OF ENERGY ENGINEERS	DSM	215	5/31/2018	EXPENSE REPORT - DAVE REINKE	B
ASSOCIATION OF ENERGY ENGINEERS	KEY	215	1/31/2018	EXPENSE REPORT - TIM DOHERTY	B
BURNSVILLE CHAMBER OF COMMERCE	COMMREL	1,345	1/31/2018	2018-MEMBERSHIP	A
BURNSVILLE ROTARY FOUNDATION	SHELDON	400	1/31/2018	J SHELDON 1/1-6/30/18	C
BURNSVILLE ROTARY FOUNDATION	SHELDON	350	7/31/2018	J SHELDON 7/1-12/31/18	C
CANNON FALLS AREA C OF C	COMMREL	450	1/31/2018	MEMBERSHIP 2018	A
CANNON FALLS AREA HISTORICAL	ACS	100	12/31/2018	MEMBERSHIP 12/2018-11/2019	C
CERTIFIED ENERGY MANAGER	ACS	300	12/31/2018	EXPENSE REPORT - JANE SIEBENALER	B
DAKOTA CTY REGIONAL C OF C	COMMREL	1,700	1/31/2018	2018 DUES	A
ECONOMIC DEVELOPMENT ASSOC OF MN (EDAM)	ECO	495	1/31/2018	M LOFTHUS/P JOHNSON	B
ELKO NEW MARKET CHAMBER	COMMREL	200	3/31/2018	DUES 5/31/17-6/1/18	A
ENVIRONMENTAL INITIATIVE	ENVIRON	600	1/31/2018	2018 CORP MEMBERSHIP	D
ENVIRONMENTAL INITIATIVE	ENVIRON	600	11/30/2018	MEMBERSHIP 11/1/18-10/31/19	D
GREAT PLAINS INSTITUTE	ELECCAR	2,500	9/30/2018	DUES 9/2018-8/2019	D
GREATER MSP	ECO	10,000	1/31/2018	2018 ANNUAL MEMBERSHIP	A
HASTINGS AREA CHAMBER OF COMM	COMMREL	825	4/30/2018	PJOHNSON MBRSHP 4/1/18-3/31/1	A
INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	AMS	294	11/30/2018	EXPENSE REPORT - CRAIG TURNER	B
INTERNATIONAL ECONOMIC DEVELOPMENT COUNCIL (IEDC)	COMMREL	185	7/31/2018	P JOHNSON 7/1/18-6/30/19	B
INTERNATIONAL ECONOMIC DEVELOPMENT COUNCIL (IEDC)	ECO	420	8/30/2018	M LOFTHUS 8/1/18-7/31/19	B
INTERNATIONAL RIGHT OF WAY ASSOC. (IRWA)	EDU	271	1/31/2018	T SCHMITZ 2018 DUES	B
INTERNATIONAL RIGHT OF WAY ASSOC. (IRWA)	EDU	286	1/31/2018	C KNUDSEN 2018 DUES	B
LAKE BYLLESBY IMPROVEMENT ASSN	ECO	50	1/31/2018	DUES 2018	A
LAKEVILLE AREA ARTS CENTER	ACS	100	1/31/2018	MEMBERSHIP DUES	A
LAKEVILLE AREA CHAMBER OF COMM	COMMREL	855	1/31/2018	2018 MEMBERSHIP	A
LAKEVILLE AREA CHAMBER OF COMM	COMMREL	855	12/31/2018	2019 MEMBERSHIP	A
LAKEVILLE AREA HISTORICAL SOC	ACS	50	1/31/2018	2018 CORP MEMBERSHIP	C
METROPOLITAN UTILITY COORD COM	SAF	1,000	1/31/2018	2018 MEMBERHSIP DUES	D
MID-AMERICA ECONOMIC DEVELOPMENT COUNCIL (MAEDC)	ECO	125	1/31/2018	M LOFTHUS 2018 MEMBERSHIP	B
MIDWEST LAWSON USER GROUP	LAWSON	250	1/31/2018	C HENKE MEMBERSHIP	B
MINNESOTA CHAMBER OF COMMERCE	COMMREL	2,455	6/30/2018	MEMBERSHIP 6/1/18-5/31/19	A

ORGANIZATION	PROJECT	AMOUNT	DATE	DESCRIPTION/EMPLOYEE	*PURPOSE
MINNESOTA SAFETY COUNCIL	SAF	545	1/31/2018	2018 MEMBERSHIP	B
MINNESOTA SHERIFFS' ASSN	ACS	25	1/31/2018	MEMBERSHIP DUES	E
MN ASSN OF CHURCH FACILITY MGR	DSM	300	1/31/2018	2018 DUES	D
MN DEED	ECO	625	1/31/2018	M LOFTHUS 2018 MBRSHP	B
MN DEPT OF PUBLIC SAFETY	HAZARD	25	2/28/2018	HAZ CHEM INVENTORY FEE	E
MN GEOTHERMAL HEAT PUMP ASSN	DSM	250	7/31/2018	D REINKE 7/1/18-6/30/19	B
MN POLLUTION CONTROL AGENCY	HAZARD	330	3/31/2018	HAZARDOUS WASTE FEES	E
MN RURAL ELECTRIC ASSOCIATION	AMS	76,005	1/31/2018	1ST HALF GENL & EDU DUES	D
MN RURAL ELECTRIC ASSOCIATION	AMS	76,005	7/31/2018	2ND HALF GENL & EDU DUES	D
MN SOCIETY OF CPAS	FIN	300	3/31/2018	EXPENSE REPORT-CARLA S. HENKE	B
MN STATE BOARD OF ACCOUNTANCY	FIN	27	10/31/2018	EXPENSE REPORT-CARLA S. HENKE	B
MRA-THE MANAGEMENT ASSOCIATION	HRP	1,500	10/31/2018	M MEHRHOFF 10/1/18-10/1/19	B
NATIONAL FIRE PROTECTION ASN	BLD	175	4/30/2018	V FRANDRUP 4/01/18-3/31/19	B
NATIONAL RURAL ECONOMIC DEVELOPERS ASSOCIATION (NREDA)	ECO	275	1/31/2018	P JOHNSON 2018 MEMBERSHIP	B
NATIONAL RURAL ECONOMIC DEVELOPERS ASSOCIATION (NREDA)	ECO	275	1/31/2018	M LOFTHUS 2018 MEMBERSHIP	B
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION (NRECA)	SAF	110	1/31/2018	LOSS CTRL MEMBERSHIP 2018	B
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION (NRECA)	PUBREL	175	1/31/2018	CCC MEMBERSHIP 2018/J MILLER	B
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION (NRECA)	AMS	80,579	8/31/2018	2018 MEMBERSHIP DUES	D
NATIONAL SOCIETY OF ACCOUNTANTS FOR COOPERATIVES (NSAC)	FIN	200	1/31/2018	EXPENSE REPORT-CARLA S. HENKE	B
PUBLIC RELATIONS SOCIETY OF AMERICA (PRSA)	PUBREL	330	2/28/2018	J MILLER 2/1/18-1/31/19	B
RECYCLING ASSOCIATION OF MN	ENVIRON	200	2/28/2018	12 MO BUS MBRSHIP	D
RIVER HEIGHTS CHAMBER	COMMREL	1,234	1/31/2018	2018 MEMBERSHIP/P JOHNSON	A
ROTARY CLUB OF APPLE VALLEY	AMS	63	2/28/2018	G MILLER 1/1-3/31/18	C
ROTARY CLUB OF APPLE VALLEY	AMS	63	11/30/2018	G MILLER 7/1/18-9/30/18	C
ROTARY CLUB OF APPLE VALLEY	AMS	63	11/30/2018	G MILLER 10/1/18-12/31/18	C
ROTARY CLUB OF APPLE VALLEY	AMS	63	11/30/2018	G MILLER 4/1/18-6/30/18	C
ROTARY CLUB OF FARMINGTON	MKT	175	1/31/2018	JAN-MAR 2018 DUES/L LANDWEHR	C
ROTARY CLUB OF FARMINGTON	MKT	175	4/30/2018	4TH QTR/APR-JUN18-LLANDWEHR	C
ROTARY CLUB OF FARMINGTON	MKT	175	7/31/2018	L LANDWEHR JUL-SEP DUES	C
ROTARY CLUB OF FARMINGTON	MKT	175	11/30/2018	L LANDWEHR 2ND QTR 2018-2019	C
ROTARY CLUB OF FARMINGTON	MKT	175	12/31/2018	L LANDWEHR 3RD QTR 2018-2019	C
RURAL ELECTRIC MANAGERS ASSOCIATION (REMA)	AMS	1,800	1/31/2018	2018 DUES	D
SAM'S CLUB	Various	84	3/31/2018	MEMBERSHIPS	E
SOCIETY FOR HUMAN RESOURCE MANAGEMENT (SHRM)	HRP	209	7/31/2018	M MEHRHOFF 7/1/18-6/30/19	B
US BANK-ASSN OF ENERGY ENGINEERS	KEY	300	1/31/2018	CC Recap-Timothy J. Doherty	B
US BANK-ASSN OF ENERGY ENGINEERS	DSM	195	3/31/2018	CC Recap-Tyler W. Kashdan	B
US BANK-BOARD OF AELSLAGID	ETS	123	7/31/2018	CC Recap-Craig C. Turner	B
US BANK-BOARD OF AELSLAGID	ETS	123	7/31/2018	CC Recap-Jeffrey L. Schoenecke	B
US BANK-DAKOTA COUNTY	HAZARD	579	4/30/2018	CC Recap-Bernard M. Kolnberger	E
US BANK-DEPT OF AGRICULTURE	USO	26	12/31/2018	CC Recap-Bernard M. Kolnberger	E

ORGANIZATION	PROJECT	AMOUNT	DATE	DESCRIPTION/EMPLOYEE	*PURPOSE
US BANK-INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	ETS	291	1/31/2018	CC Recap-Jeffrey L Schoenecker	B
US BANK-INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	EDU	291	1/31/2018	CC Recap-Craig C Turner	B
US BANK-INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	NCD	236	1/31/2018	CC Recap-Betty Jo Kiesow	B
US BANK-INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	EDU	201	1/31/2018	CC Recap-Glenda L. Hewitt	B
US BANK-INSTITUTE OF ELECTRICAL & ELECTRONICS ENGINEERS (IEEE)	ETS	235	9/30/2018	CC Recap-Patrick M Hughes	B
US BANK-MN SOCIETY OF PROFESSIONAL ENGINEERS (MSPE)	ETS	384	5/31/2018	CC Recap-Craig C. Turner	B
US BANK-NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	AUO	299	10/31/2018	CC Recap-Jeffrey L Schoenecker	B
US BANK-NFPA NATL FIRE PROTECTION ASSOCIATION	ETS	175	10/31/2018	CC Recap-Patrick M Hughes	B
US BANK-SMK*SURVEYMONKEY.COM	HRP	360	11/30/2018	CC Recap-Christene D. Dodge-Ra	E
US BANK-SOCIETY FOR HUMAN RESOURCE MANAGEMENT (SHRM)	HRP	209	8/31/2018	CC Recap-Christene D. Dodge-Ra	B
US CHAMBER OF COMMERCE	COMMREL	500	2/28/2018	P JOHNSON 2/1/18-1/31/19	A
ALLOWED DUES AND MEMBERSHIPS		$ 276,823			
DISALLOWED DUES AND MEMBERSHIPS (BRANDING PROJECT)		48,725			
TOTAL DUES AND MEMBERSHIPS		$ 325,548			

*PURPOSE:

A-Promotes development of business, industry & civic interest in various communities

B-Employee memberships in technical trade organizations providing information to improve knowledge and productivity

C-Civic & community service organizations provide access to information to equip our employees and directors to function more effectively

D-Educates and informs utility employees

E-DEA Administration

Workpaper 19
Donations/Charitable Contributions

Dakota Electric Association
Summary of Donations/Charitable Contributions
2018

COMMUNITY DONATIONS	AMOUNT	DATE
360 COMMUNITIES	$ 300	5/31/2018
ALL SAINTS MUSIC FESTIVAL	250	1/31/2018
AMERICAN CANCER SOCIETY	250	5/30/2018
AMERICAN LEGION POST 594	200	1/31/2018
APPLE VALLEY FREEDOM DAYS	500	5/31/2018
APPLE VALLEY HIGH SCHOOL	200	1/31/2018
ARBORS AT RIDGES	200	3/31/2018
BURNSVILLE COMMUNITY FOUNDATN	200	3/31/2018
BURNSVILLE COMMUNITY FOUNDATN	500	9/30/2018
BURNSVILLE COMMUNITY FOUNDATN	250	12/31/2018
BURNSVILLE VISUAL ARTS SOCIETY	25	3/31/2018
CANNON ARTS BOARD	250	5/30/2018
CANNON FALLS AREA C OF C	150	4/30/2018
CANNON FALLS, CITY	200	11/30/2018
CHRISTUS VICTOR LUTHERAN CHRCH	200	11/30/2018
CITY OF APPLE VALLEY	500	1/31/2018
CITY OF ELKO NEW MARKET	300	5/31/2018
CITY OF FARMINGTON	100	3/31/2018
CITY OF INVER GROVE HEIGHTS	200	10/31/2018
COMMUNITY ACTION CTR OF NFLD	200	12/31/2018
DAKOTA CITY HERITAGE VILLAGE	500	4/30/2018
DAKOTA COUNTY 4-H FEDERATION	250	10/31/2018
DAKOTA COUNTY HISTORICAL SOC	200	5/31/2018
DAKOTA COUNTY HISTORICAL SOC	100	11/30/2018
DARTS	200	4/30/2018
DARTS	1,000	7/31/2018
DEFEAT OF JESSE JAMES DAY	200	3/31/2018
EAGAN CITIZENS CRIME PREV ASSN	150	4/30/2018
EAGAN KICK-START ROTARY FNDTN	200	10/31/2018
EAGAN MEN'S CHORUS	200	10/30/2018
EAGAN'S JULY 4TH FUNFEST	500	3/31/2018
ELKO NEW MARKET FIRE RELIEF	200	2/28/2018
FARMINGTON BUSINESS ASSN	150	11/30/2018
FRIENDS OF THE CANNON VLY FAIR	200	1/31/2018
FRIENDS OF THE FARMINGTON LIBR	200	11/30/2018
FRIENDS OF THE HERITAGE LIB	200	2/28/2018
GOBBLE GAIT LLC	250	9/30/2018
HASTINGS AREA CHAMBER OF COMM	500	3/31/2018
HASTINGS PUBLIC SCHOOLS FNDTN	200	11/30/2018
HOLIDAY CLASSIC TOURNAMENT	100	11/30/2018
INDEPENDENT SCHOOL DIST 192	250	9/30/2018
INTERNATIONAL FESTIVAL OF BVL	500	4/30/2018
LAKEVILLE AREA ARTS CENTER	400	8/31/2018
LAKEVILLE PUBLIC SAFETY FDTN	200	4/30/2018
LKV FRIENDS OF THE ENVIRONMENT	250	4/30/2018

COMMUNITY DONATIONS (CONTINUED)	AMOUNT	DATE
MN WOMEN OF TODAY FOUNDATION	200	5/30/2018
NATIONAL EAGLE CENTER	1,000	8/31/2018
PAN-O-PROG	500	3/31/2018
PARKRUN USA	200	6/30/2018
RANDOLPH ROCKETS BOOSTER CLUB	100	5/31/2018
ROSEMOUNT AREA ARTS COUNCIL	250	5/30/2018
ROSEMOUNT AREA ARTS COUNCIL	200	9/30/2018
ROSEMOUNT LEPRECHAUN DAYS	500	4/30/2018
ROTARY CLUB OF FARMINGTON	500	1/31/2018
ROTARY CLUB OF LAKEVILLE FDTN	500	5/31/2018
ROTARY CLUB OF ROSEMOUNT	500	2/28/2018
SOUTHERN CRUZERS CAR CLUB	200	3/31/2018
TRINITY CAMPUS	200	3/31/2018
UNITED WAY OF HASTINGS	200	5/31/2018
VELVET TONES	200	8/31/2018
SUBTOTAL COMMUNITY DONATIONS	$ 17,325	

HUMAN SERVICES DONATIONS	AMOUNT	DATE
AMERICAN HEART ASSOCIATION	$ 200	4/30/2018
AMERICAN HEART ASSOCIATION	200	4/30/2018
AMERICAN HEART ASSOCIATION	300	4/30/2018
AUGUSTANA REGENT AT BURNSVILLE	200	8/31/2018
AV ROTARY SCHOLARSHIP FOUNDATN	500	4/30/2018
BRETT HACK VASCULITIS CHARITIE	200	7/31/2018
BUNDLES OF LOVE CHARITY	500	11/30/2018
BURNSVILLE BREAKFAST ROTARY	300	4/30/2018
BURNSVILLE ROTARY FOUNDATION	500	1/31/2018
CANNON COMM INTERACTION COUNCL	200	9/30/2018
CANNON FALLS AMER LEGION #142	200	1/31/2018
COMMUNITY HEALTH CHARITIES MN	1,667	11/30/2018
DAKOTA COUNTY ATTORNEY	200	7/31/2018
DAKOTA WOODLANDS	250	8/31/2018
EASTER LUTHERAN CHURCH	200	8/31/2018
FAIRVIEW FOUNDATION	1,000	5/31/2018
FARMINGTON AMERICAN LEGION AUX	200	6/30/2018
GREATER TWIN CITIES UNITED WAY	1,667	11/30/2018
HASTINGS FIRE DEPARTMENT	200	8/31/2018
LIFEWORKS SERVICES	200	11/30/2018
MAJESTIC HILLS RANCH FOUNDATN	500	11/30/2018
MENTAL HEALTH RESOURCES INC	200	8/31/2018
MN RURAL ELECTRIC ASSOCIATION	275	4/30/2018
NATIONAL MS SOCIETY	100	3/31/2018
NATIONAL MS SOCIETY	100	6/30/2018
PANCREATIC CANCER ACTION NETWK	150	5/31/2018
PAWPADS	500	11/30/2018
PELLICCI ACE FARMINGTON	200	10/31/2018
PROACT INC	120	5/30/2018
SUPPORT OUR TROOPS	200	10/31/2018

HUMAN SERVICES DONATIONS (CONTINUED)	AMOUNT	DATE
THE FALLEN LINEMEN ORG	1,667	11/30/2018
THE OPEN DOOR	250	6/30/2018
US BANK	100	3/31/2018
US BANK	100	6/30/2018
USAFA PARENTS' CLUB OF MN	200	10/31/2018
VFW POST 7662	200	5/31/2018
SUBTOTAL HUMAN SERVICES DONATIONS	$ 13,745	

SPECIAL DONATIONS	AMOUNT	DATE
360 COMMUNITIES	$ 5,000	7/31/2018
DAKOTA COUNTY FAIR	1,000	6/30/2018
FAIRVIEW FOUNDATION	10,000	5/31/2018
ROTARY CLUB OF FARMINGTON	500	8/30/2018
YMCA OF THE GREATER TWN CITIES	2,500	3/31/2018
SUBTOTAL SPECIAL DONATIONS	$ 19,000	

YOUTH DONATIONS	AMOUNT	DATE
APPLE VALLEY HIGH SCHOOL	200	1/31/2018
APPLE VALLEY HIGH SCHOOL	200	7/31/2018
APPLE VALLEY HIGH SCHOOL	300	7/31/2018
APPLE VALLEY HIGH SCHOOL	500	9/30/2018
APPLE VALLEY HS SENIOR PARTY	250	1/31/2018
AUTISM SPEAKS	100	9/30/2018
AV BOYS BASKETBALL BOOSTERS	200	9/30/2018
AV GIRLS BASKETBALL BOOSTERS	200	9/30/2018
AVR ALPINE SKI TEAM BOOSTERS	200	10/31/2018
BURNSVILLE HIGH SCHOOL	200	5/30/2018
BURNSVILLE SENIOR CLASS PARTY	250	1/31/2018
CANNON FALLS SENIOR PARTY	250	3/31/2018
CAPONI ART PARK	500	6/30/2018
CHURCH OF ST PATRICK	100	7/31/2018
CITY OF HASTINGS	200	2/28/2018
CITY OF HASTINGS	100	9/30/2018
DAKOTA COUNTY 4-H FEDERATION	200	4/30/2018
DAKOTA COUNTY 4-H FEDERATION	120	4/30/2018
DAKOTA COUNTY 4-H FEDERATION	200	7/31/2018
DAKOTA COUNTY 4-H FEDERATION	450	8/31/2018
DAKOTA COUNTY 4-H FEDERATION	660	8/31/2018
DAKOTA COUNTY ATTORNEY	250	2/28/2018
DAKOTA COUNTY LIBRARY	500	3/31/2018
DCTC FOUNDATION	1,000	2/28/2018
DESTINATION IMAGINATION INC	200	5/31/2018
DISTRICT 196 FOUNDATION INC	200	1/31/2018
EAGAN ATHLETIC ASSOCIATON	200	3/31/2018
EAGAN FOUNDATION	500	2/28/2018
EASTVIEW HIGH SCHOOL	200	3/31/2018
EASTVIEW HIGH SCHOOL SR PARTY	250	2/28/2018
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018

YOUTH DONATIONS (CONTINUED)	AMOUNT	DATE
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018
FARMINGTON GIRLS FASTPITCH ASN	200	6/30/2018
FARMINGTON GIRLS FASTPITCH ASN	200	7/31/2018
FARMINGTON GIRLS FASTPITCH ASN	200	7/31/2018
FARMINGTON HIGH SCHOOL	200	10/31/2018
FARMINGTON SENIOR CLASS PARTY	250	1/31/2018
FARMINGTON TIGER BAND BOOSTERS	100	7/31/2018
FARMINGTON WRESTLING CLUB	150	9/30/2018
FHS HOMECOMING	150	9/30/2018
FIT ACADEMY CHARTER SCHOOL	200	7/31/2018
FTDT BOOSTER CLUB	200	7/31/2018
GIRL SCOUT TROOP 54072	200	3/31/2018
HANSON SCHOLARSHIP FUND	175	8/31/2018
HASTINGS ALL NIGHT GRAD PARTY	250	1/31/2018
HASTINGS AREA SWIM TEAM	200	1/31/2018
HASTINGS FOOTBALL CONNECTIONS	200	5/31/2018
HASTINGS HIGH SCHOOL	100	4/30/2018
HASTINGS HIGH SCHOOL	200	7/31/2018
HASTINGS SOFTBALL BOOSTER CLUB	200	4/30/2018
HEART OF THE CITY RACE	200	8/31/2018
HOPE FOR TOMORROW-RSMT CHAPTER	250	2/28/2018
INDEPENDENT SCHOOL DIST 192	200	10/31/2018
INDEPENDENT SCHOOL DIST 195	200	7/31/2018
INDEPENDENT SCHOOL DIST 195	200	8/31/2018
INDEPENDENT SCHOOL DIST 196	200	1/31/2018
INDEPENDENT SCHOOL DIST 196	200	1/31/2018
INDEPENDENT SCHOOL DIST 196	200	3/31/2018
IRISH BASEBALL BOOSTER CLUB	200	3/31/2018
JOHN BRAUN	560	8/31/2018
KIDS 'N KINSHIP	200	3/31/2018
KIDS 'N KINSHIP	250	7/31/2018
LAKEVILLE NORTH HIGH SCHOOL	500	1/31/2018
LAKEVILLE NORTH HIGH SCHOOL	200	3/31/2018
LAKEVILLE ROBOTICS	500	9/30/2018
LAKEVILLE SOUTH BOYS LACROSSE	200	3/31/2018
LIFEWORKS SERVICES	200	1/31/2018
LKV SR CLASS PARTIES/NO EIN	500	3/31/2018
LOGAN LITSCHKE	480	8/31/2018
LOUIS SCHMITZ FOUNDATION	100	5/31/2018
MEADOWVIEW ELEMENTARY SCHOOL	200	1/31/2018
MINNESOTA DARE INC	200	9/30/2018
MINNESOTA FFA FOUNDATION	170	9/30/2018
MISS IGH SCHOLARSHIP PROGRAM	100	3/31/2018
NATIONAL CHILD SAFETY COUNCIL	200	1/31/2018
NORTHERN STAR COUNCIL	250	3/31/2018
OAK RIDGE PTO	200	8/31/2018
PADRAIG'S PLACE	200	1/31/2018

YOUTH DONATIONS (CONTINUED)	AMOUNT	DATE
PAIGE PEINE	520	8/31/2018
PATRICK SCHOONOVER HEART FDTN	200	11/30/2018
RAIDERS SWIM & DIVE BOOSTERS	200	8/31/2018
RANDOLPH COMMUNITY EDUCATION	200	7/31/2018
RHS GIRLS GOLF BOOSTER CLUB	200	2/28/2018
RHS SOFTBALL BOOSTER CLUB	200	1/31/2018
ROSEMOUNT AREA ATHLETIC ASSN	200	11/30/2018
ROSEMOUNT AREA ATHLETIC ASSN	200	11/30/2018
ROSEMOUNT AREA HOCKEY ASSN	200	9/30/2018
ROSEMOUNT HALLOWEEN COMMITTEE	200	8/31/2018
ROSEMOUNT HIGH SCHOOL	200	3/31/2018
ROSEMOUNT YOUTH LACROSSE	200	3/31/2018
SADIE WAGNER	440	8/31/2018
SES SENIOR BLAST	250	1/31/2018
SESEF FOUNDATION	200	3/31/2018
SIMLEY ALL NIGHT PARTY	250	1/31/2018
SIMON SAYS GIVE	200	8/31/2018
SOUTH ST PAUL EDU FOUNDATION	200	5/31/2018
SOUTH ST PAUL HIGH SCHOOL	150	2/28/2018
SSP YOUTH BASEBALL ASSOC	200	5/31/2018
ST JOSEPH SCHOOL	200	12/31/2018
TAYLOR JERDE	640	8/31/2018
THE GARAGE	200	1/31/2018
THE LINK	250	8/31/2018
TRINITY LONE OAK LUTHERAN SCHL	200	12/31/2018
TRINITY SCHOOL AT RIVER RIDGE	200	2/28/2018
YMCA OF THE GREATER TWN CITIES	500	2/28/2018
YMCA OF THE GREATER TWN CITIES	500	2/28/2018
YMCA OF THE GREATER TWN CITIES	500	2/28/2018
SUBTOTAL YOUTH DONATIONS	$ 27,915	

OTHER DONATIONS	AMOUNT	DATE
OPERATION WARM INC	$ 500	7/31/2018
SUBTOTAL OTHER DONATIONS	$ 500	
TOTAL DONATIONS/CHARITABLE CONTRIBUTIONS	**$ 78,485**	

Workpaper 18
Advertising

2018 Advertising

<u>Advertising Included in Test Year</u> –

These ads reference Dakota Electric's energy conservation programs, how to use energy wisely, ways to lower utility bills, and energy efficiency.

A. <u>Newspaper advertising</u>

1. "Smart Home Solutions" and "Smart Home Technologies"
    - Spent from MKT/83025/CIPNEWS = $10,009
    - Run dates January – December, 2018
    - Newspapers: *Sun Thisweek*, *Cannon Falls Beacon*, *Farmington Rosemount Independent Town Pages*, *Hastings Star Gazette*

B. <u>Television advertising</u>

1. "Stephanie"
    - Spent from MKT/83015/CIPTV = $63,625
    - Run dates January – December, 2018
    - Media: Spectrum Reach (cable TV), Comcast Zone 4 (cable TV), Over the Top (online streaming video) – Dakota Electric zip code zones

C. <u>Digital advertising</u>

2. Air conditioning, air-source heat pumps, LED bulbs, electric thermal storage (ETS) water heating rebates & programs
    - Spent from MKT/83020/CIPDIGITAL = $35,842
    - Run dates January – December, 2018
    - Media: paid Search, Facebook and Instagram ads – Dakota Electric zip code zones

<u>Advertising Excluded from Test Year</u> –

These ads primarily promote Dakota Electric's public image.

A. <u>Bill inserts and other ads</u>

1. Various bill inserts and ads
    - Spent from MKT/83040/BRANDING = $4,371
    - Spent from MKT/83040/MKT = $7,667
    - Run dates Jan., Feb., March, Oct. and Dec. 2018

B. <u>Television advertising</u>

1. "Josh – Touchstone Energy"
    - Spent from MKT/83015/BRANDING = $44,979
    - Run dates: Intermittently throughout 2018
    - Media: Charter/Spectrum Communications and Comcast – Dakota County Zones

C. <u>Radio advertising</u>

1. Various sponsorship ads and safety ads
    - Spent from MKT/83010/BRANDING = $6,848
    - Intermittently throughout 2018
    - KDHL, KYMN, KDWA

"Smart Home Solutions" and "Smart Home Technologies" newspaper ads

Digital ads

Public Document
Trade Secret Data Has Been Excised

Workpaper 17
Long Term Interest Expense
Prudently Incurred

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Partner

September 4, 2019

Burl W. Haar, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota
Docket No. E-111/GR-14-482

PUBLIC DOCUMENT – TRADE SECRET INFORMATION REMOVED

Dear Dr. Haar:

Dakota Electric Association (Dakota Electric or Cooperative) is submitting the attached Workpaper 17 as part of our general rate case in the above-reference docket. This workpaper describes trade secret information related to our lenders. We are submitting both a public and non-public (trade secret) version of this workpaper. ***This document is a public document – trade secret information has been removed.***

If you or your staff has any questions regarding this workpaper, please contact me any time at (651) 463-6258.

Sincerely,
/s/
By: ______________________
Douglas R. Larson
Vice President of Regulatory Services
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
651-463-6258

**PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED**

Dakota Electric Association
Long Term Interest Expense
Prudently Incurred

In Dakota Electric's general rate case, Docket No. E-111/GR-09-175, the May 24, 2010, Order Item No. 6 stated that "Dakota Electric shall, in its next rate case, demonstrate that its long-term interest expense is prudently incurred. Such demonstration shall include data of rates offered by other lenders."

In December, 2014, Dakota Electric received a third advance against the CoBank facility of $4 million at an interest rate of [TRADE SECRET DATA EXCISED]. At the time of this advance, the comparable net interest rate available from CFC was [TRADE SECRET DATA EXCISED].

In December, 2015, Dakota Electric executed a new single advance long term debt agreement with CoBank, ACB, and received an advance of $4 million at an interest rate of [TRADE SECRET DATA EXCISED]. At the time of this advance, the comparable net interest rate available from CFC was [TRADE SECRET DATA EXCISED].

In May, 2016, Dakota Electric received a fifth advance against the CFC facility of $5 million at an interest rate of [TRADE SECRET DATA EXCISED]. At the time of this advance, the comparable net interest rate available from CoBank, ACB was [TRADE SECRET DATA EXCISED].

In September, 2017, Dakota Electric executed a new long term debt agreement with CFC, and received an advance of $10 million at an interest rate of [TRADE SECRET DATA EXCISED]. At the time of this advance, the comparable net interest rate available from CoBank, ACB was [TRADE SECRET DATA EXCISED].

In June, 2018, Dakota Electric received a second advance against the CFC facility of $10 million at an interest rate of [TRADE SECRET DATA EXCISED]. At the time of this advance, the comparable net interest rate available from CoBank, ACB was [TRADE SECRET DATA EXCISED].

Workpaper 16
Test Year Adjustments
Bridge Schedule

Dakota Electric Association
Summary of Test Year Operating Expense Adjustments

Operating Expenses	General Payroll Increase	Capital to Expense Change for Normalized Construction	Staffing Changes	Payroll Benefits	Total Payroll & Benefit Adjustments
Distribution - Operation (DO)	$ 77,906	$ (33,389)	$ (34,438)	$ (68,218)	$ (58,139)
Distribution - Maintenance (DM)	74,151	(31,779)	156,816	24,066	223,254
Consumer Accounts (CA)	55,142	-	111,823	26,741	193,706
Consumer Service & Information (CS)	26,133	-	7,671	(8,602)	25,202
Administrative & General (AG)	185,707	-	18,507	(78,031)	126,183
Depreciation & Amortization	-	-	-	-	-
Taxes - Property	-	-	-	-	-
Other (Diversified projects)	1,009	-	-	(470)	539
Total Operating Expenses	$ 420,048	$ (65,168)	$ 260,379	$ (104,514)	$ 510,745
Reference to Exhibit_(DEA-1):	Page 3	Page 4	Page 5	Page 6&7	

Operating Expenses	Total Payroll & Benefit Adjustments (above)	Depreciation	Property & Real Estate Taxes	Reduction in CIP Spending	Recovery of Rate Filing Fees Over 5 Years	Other Adjustments	Net Deduction for Disallowed Expenses	Grand Total Adjustments
Distribution - Operation (DO)	$ (58,139)	$ -	$ -	$ -	$ -	$ (324,906)	$ -	$ (383,045)
Distribution - Maintenance (DM)	223,254	-	-	-	-	19,320	-	242,574
Consumer Accounts (CA)	193,706	-	-	-	-	187,148	-	380,854
Consumer Service & Information (CS)	25,202	-	-	(200,296)	-	2,300	(7,667)	(180,461)
Administrative & General (AG)	126,183	-	-	-	82,000	16,433	(152,833)	71,783
Depreciation & Amortization	-	404,073	-	-	-	-	-	404,073
Taxes - Property	-	-	178,507	-	-	-	-	178,507
Other Deductions	539	-	-	-	-	-	(39,244)	(38,705)
Total Operating Expenses	$ 510,745	$ 404,073	$ 178,507	$ (200,296)	$ 82,000	$ (99,705)	$ (199,744)	$ 675,580
Reference to Exhibit_(DEA-1):	See above	Page 8	Page 8	Page 9	Page 10	Page 9 &10	Page 10	Page 2

Workpaper 15
Travel, Entertainment and Related Employee Expenses

Workpaper 15
Minn. Statute 216B.16, subd. 17
Travel, entertainment, and related employee expenses
Index

Workpaper 15A
Travel Expenses

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1	3226	US BANK	Airfare	526.40	1/31/2018	2009461	CC Recap-Davin H. Peterson	11/2017-DHP	11/29/2017	EDU
2	3226	US BANK	Airfare	360.60	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
3	3226	US BANK	Airfare	612.40	1/31/2018	2009471	CC Recap-Sheryl K. Wutschke	1/2018-SKW	1/30/2018	CISIMP
4	3226	US BANK	Airfare	612.40	1/31/2018	2009471	CC Recap-Sheryl K. Wutschke	1/2018-SKW	1/30/2018	CISIMP
5	3226	US BANK	Airfare	612.40	1/31/2018	2009471	CC Recap-Sheryl K. Wutschke	1/2018-SKW	1/30/2018	CISIMP
6	3226	US BANK	Airfare	323.60	2/28/2018	2009471	CC Recap-Danielle J. Johnson	1/2018-DJJ	1/30/2018	EDU
7	3226	US BANK	Airfare	323.60	2/28/2018	2009471	CC Recap-Danielle J. Johnson	1/2018-DJJ	1/30/2018	EDU
8	3226	US BANK	Airfare	6.74	2/28/2018	2009476	CC Recap-Jay R. Bauer	2/2018-JRB	3/1/2018	POWR
9	3226	US BANK	Airfare	474.60	2/28/2018	2009476	CC Recap-Michael G. Fosse	2/2018-MGF	3/1/2018	ACS
10	3226	US BANK	Airfare	283.60	2/28/2018	2009476	CC Recap-Danielle J. Johnson	2/2018-DJJ	3/1/2018	EDU
11	3226	US BANK	Airfare	283.60	2/28/2018	2009476	CC Recap-Danielle J. Johnson	2/2018-DJJ	3/1/2018	EDU
12	3226	US BANK	Airfare	25.00	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
13	3226	US BANK	Airfare	25.00	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
14	3226	US BANK	Airfare	25.00	2/28/2018	2009476	CC Recap-Davin H. Peterson	2/2018-DHP	3/1/2018	ETS
15	5426	PAUL A TRAPP	Airfare	496.66	2/28/2018	2957	EXPENSE REPORT	FEB/2018	2/28/2018	PTRAPP
16	6718	TIM DOHERTY	Airfare	266.40	2/28/2018	355815	EXPENSE REPORT	JAN/2018	2/1/2018	NETTECH
17	8207	JOHN D DEYOE	Airfare	230.95	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
18	2625	JANET L LEKSON	Airfare	280.13	2/28/2018	2914	EXPENSE REPORT (Accrual)	JAN/2018	1/31/2018	LEKSON
19	3226	US BANK	Airfare	25.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
20	3226	US BANK	Airfare	25.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
21	3226	US BANK	Airfare	432.40	4/30/2018	2009451	CC Recap-Sherie Wutschke	9/2017-SKW	9/29/2017	MET
22	3226	US BANK	Airfare	432.40	4/30/2018	2009451	CC Recap-Sherie Wutschke	9/2017-SKW	9/29/2017	MET
23	3226	US BANK	Airfare	256.60	4/30/2018	2009471	CC Recap-Jeffrey L. Schoenecke	1/2018-JLS	1/30/2018	EDU
24	3226	US BANK	Airfare	25.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
25	3226	US BANK	Airfare	75.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
26	3226	US BANK	Airfare	25.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
27	3226	US BANK	Airfare	552.40	4/30/2018	2009486	CC Recap-Jane E. Siebenaler	4/2018-JES	4/30/2018	EDU
28	3226	US BANK	Airfare	552.40	4/30/2018	2009486	CC Recap-Jane E. Siebenaler	4/2018-JES	4/30/2018	EDU
29	3226	US BANK	Airfare	594.60	5/31/2018	2009486	CC Recap-Tanya S. Wolfs	4/2018-TSW	4/30/2018	EDU
30	3226	US BANK	Airfare	323.40	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
31	2625	JANET L LEKSON	Airfare	516.50	5/31/2018	2991	EXPENSE REPORT (Accrual)	MAR/2018	3/28/2018	LEKSON
32	3226	US BANK	Airfare	453.40	6/30/2018	2009490	CC Recap-Grant S. Baumberger	5/2018-GSB	5/31/2018	EDU
33	3226	US BANK	Airfare	25.00	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
34	3226	US BANK	Airfare	25.00	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
35	337	MN RURAL ELECTRIC ASSOCIATION	Airfare	2,322.22	7/31/2018	360874	2018 YOUTH TOUR EXP	INV00013571	8/28/2018	YOUTH
36	3226	US BANK	Airfare	262.41	7/31/2018	2009490	CC Recap-Joseph A. Miller	5/2018-JAM	5/31/2018	BRANDING
37	3226	US BANK	Airfare	542.40	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
38	3226	US BANK	Airfare	25.00	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
39	3226	US BANK	Airfare	25.00	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
40	3226	US BANK	Airfare	609.40	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
41	3226	US BANK	Airfare	263.40	8/31/2018	2009501	CC Recap-Mark W. Lofthus	7/2018-MWL	7/31/2018	ECO
42	3226	US BANK	Airfare	232.40	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
43	3226	US BANK	Airfare	576.40	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
44	*3226*	*US BANK*	*Airfare*	*179.40*	*9/30/2018*	*2009486*	*CC Recap-Grant S. Baumberger*	*4/2018-GSB*	*4/30/2018*	*AGI2018*
45	3226	US BANK	Airfare	47.06	9/30/2018	2009512	CC Recap-Margaret (Peggy) P Jo	9/2018-PPJ	10/1/2018	COMMREL
46	3226	US BANK	Airfare	0.14	9/30/2018	2009512	CC Recap-Margaret (Peggy) P Jo	9/2018-PPJ	10/1/2018	COMMREL
47	3226	US BANK	Airfare	25.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
48	3226	US BANK	Airfare	25.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
49	3226	US BANK	Airfare	25.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
50	3226	US BANK	Airfare	25.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
51	3226	US BANK	Airfare	458.40	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	EDU
52	3226	US BANK	Airfare	458.40	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	EDU
53	3226	US BANK	Airfare	379.40	9/30/2018	2009512	CC Recap-Joseph A. Miller	9/2018-JAM	10/1/2018	BRANDING
54	*4042*	*CRAIG TURNER*	*Airfare*	*254.40*	*9/30/2018*	*361935*	*EXPENSE REPORT*	*SEP/2018*	*10/9/2018*	*AGI2018*

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
55	2625	JANET L LEKSON	Airfare	386.40	9/30/2018	3136	EXPENSE REPORT (Accrual)	JUL/2018	7/31/2018	LEKSON
56	2938	CARLA HENKE	Airfare	380.40	9/30/2018		EXPENSE REPORT (Accrual)	JUL/2018	7/31/2018	EDU
57	3226	US BANK	Airfare	75.00	10/31/2018	2009520	CC Recap-Glenda Hewitt	10/2018-GLH	10/31/2018	EDU
58	3226	US BANK	Airfare	75.00	10/31/2018	2009520	CC Recap-Glenda Hewitt	10/2018-GLH	10/31/2018	EDU
59	3226	US BANK	Airfare	402.40	10/31/2018	2009520	CC Recap-Jane E. Siebenaler	10/2018-JES	10/31/2018	EDU
60	*4042*	*CRAIG TURNER*	*Airfare*	*326.40*	*10/31/2018*		*EXPENSE REPORT (Accrual)*			*AGI2018*
61	2305	GERALD F PITTMAN JR	Airfare	330.40	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
62	2895	DOUGLAS R LARSON	Airfare	586.40	11/30/2018	3224	EXPENSE REPORT	SEP/2018	10/12/2018	REG
63	3048	MARGARET D SCHREINER	Airfare	311.40	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
64	3226	US BANK	Airfare	432.40	11/30/2018	2009526	CC Recap-Michael G. Fosse	11/2018-MGF	11/30/2018	ACS
65	7138	GERI L WACHTER	Airfare	239.60	11/30/2018	3169	EXPENSE REPORT	AUG/2018	8/31/2018	TIMETRACK
66	8060	DAVID S JONES	Airfare	411.40	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
67	3226	US BANK	Airfare	216.40	12/31/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
68	3226	US BANK	Airfare	30.00	12/31/2018	2009534	CC Recap-Michael G. Fosse	12/2018-MGF	12/31/2018	ACS
69	3226	US BANK	Airfare	30.00	12/31/2018	2009534	CC Recap-Michael G. Fosse	12/2018-MGF	12/31/2018	ACS
70	3226	US BANK	Airfare	325.40	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
71	3226	US BANK	Airfare	30.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
72	3226	US BANK	Airfare	30.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
		Total Company - Airfare		**$ 21,463.01**						
73	7816	TANYA S WOLFS	Mileage	95.38	1/31/2018	355496	EXPENSE REPORT	JAN/2018-EX	1/18/2018	EDU
74	4919	CLAY VAN DE BOGART	Mileage	50.14	1/31/2018	355790	EXPENSE REPORT	JAN/2018	1/30/2018	VAN
75	2305	GERALD F PITTMAN JR	Mileage	13.08	1/31/2018	2915	EXPENSE REPORT	JAN/2018	1/31/2018	PITTMAN
76	2625	JANET L LEKSON	Mileage	31.07	1/31/2018	2914	EXPENSE REPORT	JAN/2018	1/31/2018	LEKSON
77	3046	WILLIAM F HOLTON	Mileage	10.90	1/31/2018	2911	EXPENSE REPORT	JAN/2018	1/31/2018	HOLTON
78	3048	MARGARET D SCHREINER	Mileage	81.75	1/31/2018	2916	EXPENSE REPORT	JAN/2018	1/31/2018	SCHREINER
79	3052	JAMES F SHELDON	Mileage	30.52	1/31/2018	2918	EXPENSE REPORT	JAN/2018	1/31/2018	SHELDON
80	3227	JUDITH H KIMMES	Mileage	55.59	1/31/2018	2913	EXPENSE REPORT	JAN/2018	1/31/2018	KIMMES
81	5426	PAUL A TRAPP	Mileage	21.80	1/31/2018	2919	EXPENSE REPORT	JAN/2018	1/31/2018	PTRAPP
82	5886	KENNETH H DANNER	Mileage	10.90	1/31/2018	2908	EXPENSE REPORT	JAN/2018	1/31/2018	DANNER
83	7867	PAUL D R BAKKEN	Mileage	15.26	1/31/2018	2906	EXPENSE REPORT	JAN/2018	1/31/2018	BAKKEN
84	8060	DAVID S JONES	Mileage	10.90	1/31/2018	2912	EXPENSE REPORT	JAN/2018	1/31/2018	JONES
85	8207	JOHN D DEYOE	Mileage	21.80	1/31/2018	2909	EXPENSE REPORT	JAN/2018	1/31/2018	DEYOE
86	6936	JEFFERY L SCHOENECKER	Mileage	69.76	1/31/2018	2924	EXPENSE REPORT	JAN/2018	2/2/2018	ETS
87	2899	MEHRHOFF, MALINDA R	Mileage	20.71	1/31/2018	355925	EXPENSE REPORT	JAN/2018	2/6/2018	HRP
88	2899	MEHRHOFF, MALINDA R	Mileage	75.21	1/31/2018	355925	EXPENSE REPORT	JAN/2018	2/6/2018	EDU
89	4042	CRAIG TURNER	Mileage	46.87	1/31/2018	356007	EXPENSE REPORT	JAN/2018	2/8/2018	EDU
90	4573	RICHARD W TEEGARDEN	Mileage	21.80	2/28/2018	356403	EXPENSE REPORT	FEB/2018	2/27/2018	EDU
91	4919	CLAY VAN DE BOGART	Mileage	35.97	2/28/2018	356407	EXPENSE REPORT	FEB/2018	2/27/2018	VAN
92	2305	GERALD F PITTMAN JR	Mileage	78.70	2/28/2018	2953	EXPENSE REPORT	FEB/2018	2/28/2018	PITTMAN
93	2625	JANET L LEKSON	Mileage	97.01	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
94	3046	WILLIAM F HOLTON	Mileage	10.90	2/28/2018	2948	EXPENSE REPORT	FEB/2018	2/28/2018	HOLTON
95	3048	MARGARET D SCHREINER	Mileage	78.48	2/28/2018	2955	EXPENSE REPORT	FEB/2018	2/28/2018	SCHREINER
96	3052	JAMES F SHELDON	Mileage	32.70	2/28/2018	2956	EXPENSE REPORT	FEB/2018	2/28/2018	SHELDON
97	3227	JUDITH H KIMMES	Mileage	30.52	2/28/2018	2951	EXPENSE REPORT	FEB/2018	2/28/2018	KIMMES
98	5426	PAUL A TRAPP	Mileage	46.33	2/28/2018	2957	EXPENSE REPORT	FEB/2018	2/28/2018	PTRAPP
99	5886	KENNETH H DANNER	Mileage	21.80	2/28/2018	2944	EXPENSE REPORT	FEB/2018	2/28/2018	DANNER
100	6936	JEFFERY L SCHOENECKER	Mileage	25.07	2/28/2018	2954	EXPENSE REPORT	FEB/2015	2/28/2018	ETS
101	7867	PAUL D R BAKKEN	Mileage	15.26	2/28/2018	2942	EXPENSE REPORT	FEB/2018	2/28/2018	BAKKEN
102	8060	DAVID S JONES	Mileage	21.80	2/28/2018	2949	EXPENSE REPORT	FEB/2018	2/28/2018	JONES
103	8207	JOHN D DEYOE	Mileage	87.21	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
104	2899	MEHRHOFF, MALINDA R	Mileage	21.26	2/28/2018	356511	EXPENSE REPORT	FEB/2018	3/6/2018	HRP
105	2899	MEHRHOFF, MALINDA R	Mileage	35.43	2/28/2018	356511	EXPENSE REPORT	FEB/2018	3/6/2018	EDU

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
106	2955	VICKI L AUBRECHT	Mileage	85.02	2/28/2018	356493	EXPENSE REPORT	FEB/2018	3/6/2018	IFS
107	2890	KIESOW, BETTY JO A	Mileage	14.58	2/28/2018	356562	EXPENSE REPORT	FEB/2018	3/8/2018	LOC
108	3818	JOE A MILLER	Mileage	10.90	3/31/2018	356568	EXPENSE REPORT	MAR/2018	3/8/2018	PUBREL
109	4573	RICHARD W TEEGARDEN	Mileage	81.75	2/28/2018	356583	EXPENSE REPORT	FEB/2018-2	3/8/2018	EDU
110	4573	RICHARD W TEEGARDEN	Mileage	79.03	3/31/2018	356583	EXPENSE REPORT	MAR/2018	3/8/2018	IFS
111	8704	THOMAS L COAKLEY	Mileage	29.43	3/31/2018	356652	EXPENSE REPORT	FEB/2018	3/13/2018	EDU
112	6936	JEFFERY L SCHOENECKER	Mileage	320.46	3/31/2018	2974	EXPENSE REPORT	MAR/2018	3/16/2018	EDU
113	2908	DAVID S REINKE	Mileage	59.95	3/31/2018	356912	EXPENSE REPORT	MAR/2018	3/27/2018	DSM
114	4919	CLAY VAN DE BOGART	Mileage	37.06	3/31/2018	356922	EXPENSE REPORT	MAR/2018	3/27/2018	VAN
115	8528	TYLER W KASHDAN	Mileage	80.12	3/31/2018	356901	EXPENSE REPORT	MAR/2018	3/27/2018	DSM
116	2305	GERALD F PITTMAN JR	Mileage	76.19	3/31/2018	2993	EXPENSE REPORT	MAR/2018	3/28/2018	PITTMAN
117	2625	JANET L LEKSON	Mileage	18.53	3/31/2018	2991	EXPENSE REPORT	MAR/2018	3/28/2018	LEKSON
118	3046	WILLIAM F HOLTON	Mileage	10.90	3/31/2018	2987	EXPENSE REPORT	MAR/2018	3/28/2018	HOLTON
119	3048	MARGARET D SCHREINER	Mileage	64.31	3/31/2018	2994	EXPENSE REPORT	MAR/2018	3/28/2018	SCHREINER
120	3227	JUDITH H KIMMES	Mileage	56.68	3/31/2018	2990	EXPENSE REPORT	MAR/2018	3/28/2018	KIMMES
121	5426	PAUL A TRAPP	Mileage	43.60	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
122	5886	KENNETH H DANNER	Mileage	126.44	3/31/2018	2982	EXPENSE REPORT	MAR/2018	3/28/2018	DANNER
123	7867	PAUL D R BAKKEN	Mileage	15.26	3/31/2018	2980	EXPENSE REPORT	MAR/2018	3/28/2018	BAKKEN
124	8060	DAVID S JONES	Mileage	10.90	3/31/2018	2988	EXPENSE REPORT	MAR/2018	3/28/2018	JONES
125	8207	JOHN D DEYOE	Mileage	297.03	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
126	8650	STEPHANIE M PEDERSON	Mileage	52.76	3/31/2018	356957	EXPENSE REPORT	MAR/2018	3/29/2018	ELECCAR
127	2899	MEHRHOFF, MALINDA R	Mileage	149.33	3/31/2018	356998	EXPENSE REPORT	MAR/2018	4/3/2018	EDU
128	2899	MEHRHOFF, MALINDA R	Mileage	13.08	3/31/2018	356998	EXPENSE REPORT	MAR/2018	4/3/2018	HRP
129	2899	MEHRHOFF, MALINDA R	Mileage	55.60	4/30/2018	357417	EXPENSE REPORT	APR/2018	4/26/2018	EDU
130	2899	MEHRHOFF, MALINDA R	Mileage	46.87	4/30/2018	357417	EXPENSE REPORT	APR/2018	4/26/2018	WELLNESS
131	2305	GERALD F PITTMAN JR	Mileage	51.23	4/30/2018	3035	EXPENSE REPORT	APR/2018	5/1/2018	PITTMAN
132	2625	JANET L LEKSON	Mileage	65.40	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
133	3046	WILLIAM F HOLTON	Mileage	21.80	4/30/2018	3031	EXPENSE REPORT	APR/2018	5/1/2018	HOLTON
134	3048	MARGARET D SCHREINER	Mileage	73.03	4/30/2018	3037	EXPENSE REPORT	APR/2018	5/1/2018	SCHREINER
135	3052	JAMES F SHELDON	Mileage	46.87	4/30/2018	3038	EXPENSE REPORT	APR/2018	5/1/2018	SHELDON
136	3227	JUDITH H KIMMES	Mileage	46.87	4/30/2018	3033	EXPENSE REPORT	APR/2018	5/1/2018	KIMMES
137	4919	CLAY VAN DE BOGART	Mileage	63.22	4/30/2018	357654	EXPENSE REPORT	APR/2018	5/1/2018	VAN
138	5426	PAUL A TRAPP	Mileage	65.40	4/30/2018	3039	EXPENSE REPORT	APR/2018	5/1/2018	PTRAPP
139	5886	KENNETH H DANNER	Mileage	47.96	4/30/2018	3027	EXPENSE REPORT	APR/2018	5/1/2018	DANNER
140	6936	JEFFERY L SCHOENECKER	Mileage	42.51	4/30/2018	3036	EXPENSE REPORT	APR/2018	5/1/2018	EDU
141	7867	PAUL D R BAKKEN	Mileage	15.26	4/30/2018	3026	EXPENSE REPORT	APR/2018	5/1/2018	BAKKEN
142	8060	DAVID S JONES	Mileage	10.90	4/30/2018	3032	EXPENSE REPORT	APR/2018	5/1/2018	JONES
143	8207	JOHN D DEYOE	Mileage	117.18	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
144	2890	KIESOW, BETTY JO A	Mileage	258.23	4/30/2018	357888	EXPENSE REPORT	APR/2018	5/8/2018	LOC
145	3818	JOE A MILLER	Mileage	8.72	4/30/2018	357952	EXPENSE REPORT	APR-24-18	5/10/2018	PUBREL
146	2884	DENISE D HRNCIR	Mileage	11.99	5/31/2018	357998	EXPENSE REPORT	MAY-1-18	5/15/2018	HRP
147	4042	CRAIG TURNER	Mileage	110.64	4/30/2018	358013	EXPENSE REPORT	APR-19-18	5/15/2018	ETS
148	2899	MEHRHOFF, MALINDA R	Mileage	84.48	5/31/2018	358302	EX REPORT	MAY/2018	5/24/2018	EDU
149	2625	JANET L LEKSON	Mileage	21.80	5/31/2018	358517	EXPENSE REPORT	MAY/2018	6/4/2018	LEKSON
150	4919	CLAY VAN DE BOGART	Mileage	53.42	5/31/2018	358598	EXPENSE REPORT	MAY/2018	6/7/2018	VAN
151	2305	GERALD F PITTMAN JR	Mileage	44.15	5/31/2018	3076	EXPENSE REPORT	MAY/2018	6/8/2018	PITTMAN
152	2890	KIESOW, BETTY JO A	Mileage	62.86	5/31/2018	3072	EXPENSE REPORT	MAY/2018	6/8/2018	STMTGS
153	3046	WILLIAM F HOLTON	Mileage	21.80	5/31/2018	3070	EXPENSE REPORT	MAY/2018	6/8/2018	HOLTON
154	3048	MARGARET D SCHREINER	Mileage	99.19	5/31/2018	3077	EXPENSE REPORT	MAY/2018	6/8/2018	SCHREINER
155	3052	JAMES F SHELDON	Mileage	46.87	5/31/2018	3078	EXPENSE REPORT	MAY/2018	6/8/2018	SHELDON
156	3227	JUDITH H KIMMES	Mileage	93.74	5/31/2018	3073	EXPENSE REPORT	MAY/2018	6/8/2018	KIMMES
157	5426	PAUL A TRAPP	Mileage	81.75	5/31/2018	3079	EXPENSE REPORT	MAY/2018	6/8/2018	PTRAPP
158	5886	KENNETH H DANNER	Mileage	34.88	5/31/2018	3067	EXPENSE REPORT	MAY/2018	6/8/2018	DANNER
159	7867	PAUL D R BAKKEN	Mileage	15.26	5/31/2018	3066	EXPENSE REPORT	MAY/2018	6/8/2018	BAKKEN

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
160	8060	DAVID S JONES	Mileage	16.35	5/31/2018	3071	EXPENSE REPORT	MAY/2018	6/8/2018	JONES
161	8207	JOHN D DEYOE	Mileage	95.38	5/31/2018	3068	EXPENSE REPORT	MAY/2018	6/8/2018	DEYOE
162	3818	JOE A MILLER	Mileage	34.34	5/30/2018	358655	EXPENSE REPORT	MAY/2018	6/12/2018	PUBREL
163	2908	DAVID S REINKE	Mileage	29.98	6/30/2018	358859	EXPENSE REPORT	JUNE/2018	6/21/2018	DSM
164	2908	DAVID S REINKE	Mileage	41.42	6/30/2018	358859	EXPENSE REPORT	JUNE/2018	6/21/2018	GPUMPRES
165	7285	MIKE PLUTOWSKI	Mileage	190.75	6/30/2018	358857	EXPENSE REPORT	JUNE/2018	6/21/2018	EDU
166	2955	VICKI L AUBRECHT	Mileage	33.79	6/30/2018	359107	EXPENSE REPORT	JUNE/2018	6/28/2018	IFS
167	4919	CLAY VAN DE BOGART	Mileage	11.99	6/30/2018	359175	EXPENSE REPORT	JUNE/2018	7/3/2018	VAN
168	7816	TANYA S WOLFS	Mileage	182.03	6/30/2018	359181	EXPENSE REPORT	JUNE/2018	7/3/2018	EDU
169	7816	TANYA S WOLFS	Mileage	27.25	6/30/2018	359181	EXPENSE REPORT	JUNE/2018	7/3/2018	CIRC2018
170	8713	AAP OF MSP-FARMINGTON MN #2112	Mileage	16.04	6/30/2018	359151	#343/XTRACLEAR	475891	7/3/2018	VANS
171	2305	GERALD F PITTMAN JR	Mileage	13.08	6/30/2018	3102	EXPENSE REPORT	JUNE/2018	7/5/2018	PITTMAN
172	2625	JANET L LEKSON	Mileage	9.81	6/30/2018	3101	EXPENSE REPORT	JUNE/2018	7/5/2018	LEKSON
173	3046	WILLIAM F HOLTON	Mileage	10.90	6/30/2018	3098	EXPENSE REPORT	JUNE/2018	7/5/2018	HOLTON
174	3048	MARGARET D SCHREINER	Mileage	16.35	6/30/2018	3103	EXPENSE REPORT	JUNE/2018	7/5/2018	SCHREINER
175	3052	JAMES F SHELDON	Mileage	39.24	6/30/2018	3104	EXPENSE REPORT	JUNE/2018	7/5/2018	SHELDON
176	3227	JUDITH H KIMMES	Mileage	41.42	6/30/2018	3100	EXPENSE REPORT	JUNE/2018	7/5/2018	KIMMES
177	5426	PAUL A TRAPP	Mileage	121.54	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
178	5886	KENNETH H DANNER	Mileage	10.90	6/30/2018	3096	EXPENSE REPORT	JUNE/2018	7/5/2018	DANNER
179	7867	PAUL D R BAKKEN	Mileage	15.26	6/30/2018	3095	EXPENSE REPORT	JUNE/2018	7/5/2018	BAKKEN
180	8060	DAVID S JONES	Mileage	62.68	6/30/2018	3099	EXPENSE REPORT	JUNE/2018	7/5/2018	JONES
181	8207	JOHN D DEYOE	Mileage	129.71	6/30/2018	3097	EXPENSE REPORT	JUNE/2018	7/5/2018	DEYOE
182	2899	MEHRHOFF, MALINDA R	Mileage	49.60	6/30/2018	359334	EXPENSE REPORT	JUNE/2018	7/10/2018	HRP
183	2899	MEHRHOFF, MALINDA R	Mileage	32.70	6/30/2018	359334	EXPENSE REPORT	JUNE/2018	7/10/2018	EDU
184	7903	THOMAS RISTE	Mileage	42.51	6/30/2018	3112	EXPENSE REPORT	JUNE/2018	7/11/2018	LAWSON
185	3809	MARTIN BRICHTA	Mileage	32.70	7/31/2018	359598	MEAL REIMBRSMNT	JUNE/2018	7/17/2018	LAWSON
186	8116	STEVEN J MATSON	Mileage	32.70	7/31/2018	359883	EXPENSE REPORT	JUNE/2018	7/24/2018	LAWSON
187	2884	DENISE D HRNCIR	Mileage	26.16	7/31/2018	359934	EXPENSE REPORT	JULY/2018	7/26/2018	HRP
188	2899	MEHRHOFF, MALINDA R	Mileage	120.99	7/31/2018	359940	EXPENSE REPORT	JULY/2018	7/26/2018	EDU
189	8545	COREY M HINTZ	Mileage	50.69	7/31/2018	3126	EXPENSE REPORT	JULY/2018	7/27/2018	POWSUP
190	2305	GERALD F PITTMAN JR	Mileage	13.08	7/31/2018	3137	EXPENSE REPORT	JULY/2018	7/31/2018	PITTMAN
191	2625	JANET L LEKSON	Mileage	15.26	7/31/2018	3136	EXPENSE REPORT	JULY/2018	7/31/2018	LEKSON
192	2739	JULIE A SIMONSEN	Mileage	12.54	7/31/2018	360060	EXPENSE REPORT	JULY/2018	7/31/2018	CUSEVENT
193	3046	WILLIAM F HOLTON	Mileage	10.90	7/31/2018	3133	EXPENSE REPORT	JULY/2018	7/31/2018	HOLTON
194	3048	MARGARET D SCHREINER	Mileage	27.25	7/31/2018	3138	EXPENSE REPORT	JULY/2018	7/31/2018	SCHREINER
195	3052	JAMES F SHELDON	Mileage	14.17	7/31/2018	3139	EXPENSE REPORT	JULY/2018	7/31/2018	SHELDON
196	3227	JUDITH H KIMMES	Mileage	42.51	7/31/2018	3135	EXPENSE REPORT	JULY/2018	7/31/2018	KIMMES
197	4919	CLAY VAN DE BOGART	Mileage	11.99	7/31/2018	360064	EXPENSE REPORT	JULY/2018	7/31/2018	VAN
198	5426	PAUL A TRAPP	Mileage	40.88	7/31/2018	3140	EXPENSE REPORT	JULY/2018	7/31/2018	PTRAPP
199	7867	PAUL D R BAKKEN	Mileage	15.26	7/31/2018	3130	EXPENSE REPORT	JULY/2018	7/31/2018	BAKKEN
200	8060	DAVID S JONES	Mileage	16.35	7/31/2018	3134	EXPENSE REPORT	JULY/2018	7/31/2018	JONES
201	8207	JOHN D DEYOE	Mileage	132.44	7/31/2018	3132	EXPENSE REPORT	JULY/2018	7/31/2018	DEYOE
202	8545	COREY M HINTZ	Mileage	77.39	7/31/2018	3143	EXPENSE REPORT	JULY-2018	8/2/2018	AFS
203	2955	VICKI L AUBRECHT	Mileage	81.75	7/31/2018	360231	EXPENSE REPORT	JULY/2018	8/9/2018	EDU
204	3818	JOE A MILLER	Mileage	55.05	7/31/2018	360253	EXPENSE REPORT	JULY/2018	8/9/2018	PUBREL
205	3818	JOE A MILLER	Mileage	26.16	7/31/2018	360253	EXPENSE REPORT	JULY/2018	8/9/2018	CUSEVENT
206	2890	KIESOW, BETTY JO A	Mileage	125.60	7/31/2018	3152	EXPENSE REPORT	JULY/2018	8/10/2018	LOC
207	2890	KIESOW, BETTY JO A	Mileage	47.09	7/31/2018	3152	EXPENSE REPORT	JULY/2018	8/10/2018	NCD
208	2955	VICKI L AUBRECHT	Mileage	33.79	8/31/2018	360483	EXPENSE REPORT	AUG/2018	8/16/2018	EDU
209	7285	MIKE PLUTOWSKI	Mileage	4.36	8/31/2018	360521	EXPENSE REPORT	AUG/2018	8/16/2018	FAIRSHOW
210	2899	MEHRHOFF, MALINDA R	Mileage	44.15	8/31/2018	360921	EXPENSE REPORT	AUG/2018	8/30/2018	WELLNESS
211	2899	MEHRHOFF, MALINDA R	Mileage	21.80	8/31/2018	360921	EXPENSE REPORT	AUG/2018	8/30/2018	HRP
212	2899	MEHRHOFF, MALINDA R	Mileage	33.79	8/31/2018	360921	EXPENSE REPORT	AUG/2018	8/30/2018	EDU
213	8474	METRO UPHOLSTERY	Mileage	151.07	8/31/2018	360923	#212/REPAIR SEAT CUSHION	3427	8/30/2018	DIGR

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
214	2938	HENKE, CARLA S	Mileage	112.27	8/31/2018	3165	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
215	8545	COREY M HINTZ	Mileage	189.66	8/31/2018	3166	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
216	2305	GERALD F PITTMAN JR	Mileage	51.78	8/31/2018	3177	EXPENSE REPORT	AUG/2018	9/4/2018	PITTMAN
217	2625	JANET L LEKSON	Mileage	104.64	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
218	3046	WILLIAM F HOLTON	Mileage	10.90	8/31/2018	3173	EXPENSE REPORT	AUG/2018	9/4/2018	HOLTON
219	3048	MARGARET D SCHREINER	Mileage	16.35	8/31/2018	3178	EXPENSE REPORT	AUG/2018	9/4/2018	SCHREINER
220	3052	JAMES F SHELDON	Mileage	28.34	8/31/2018	3179	EXPENSE REPORT	AUG/2018	9/4/2018	SHELDON
221	3227	JUDITH H KIMMES	Mileage	28.34	8/31/2018	3175	EXPENSE REPORT	AUG/2018	9/4/2018	KIMMES
222	4919	CLAY VAN DE BOGART	Mileage	11.99	8/31/2018	361027	EXPENSE REPORT	AUG/2018	9/4/2018	VAN
223	5426	PAUL A TRAPP	Mileage	132.44	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
224	5886	KENNETH H DANNER	Mileage	109.00	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
225	7867	PAUL D R BAKKEN	Mileage	15.26	8/31/2018	3170	EXPENSE REPORT	AUG/2018	9/4/2018	BAKKEN
226	8060	DAVID S JONES	Mileage	207.10	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
227	8207	JOHN D DEYOE	Mileage	(18.53)	8/31/2018	3172	EXPENSE REPORT	AUG/2018	9/4/2018	DEYOE
228	2890	KIESOW, BETTY JO A	Mileage	132.84	8/31/2018	3182	EXPENSE REPORT	AUG/2018	9/6/2018	LOC
229	3818	JOE A MILLER	Mileage	10.90	8/31/2018	361161	EXPENSE REPORT	AUG/2018	9/11/2018	PUBREL
230	2899	MEHRHOFF, MALINDA R	Mileage	30.52	9/30/2018	361764	EXPENSE REPORT	SEP/2018	10/2/2018	HRP
231	2899	MEHRHOFF, MALINDA R	Mileage	95.92	9/30/2018	361764	EXPENSE REPORT	SEP/2018	10/2/2018	EDU
232	4919	CLAY VAN DE BOGART	Mileage	11.99	9/30/2018	361788	EXPENSE REPORT	SEPT/2018	10/2/2018	VAN
233	8865	PATRICK M HUGHES	Mileage	152.06	9/30/2018	361753	EXPENSE REPORT	SEP/2018	10/2/2018	ETS
234	2305	GERALD F PITTMAN JR	Mileage	26.16	9/30/2018	3213	EXPENSE REPORT	SEPT/2018	10/3/2018	PITTMAN
235	2625	JANET L LEKSON	Mileage	20.71	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
236	2938	HENKE, CARLA S	Mileage	65.40	9/30/2018	3207	EXPENSE REPORT	SEP/2018	10/3/2018	LAWSON
237	3046	WILLIAM F HOLTON	Mileage	10.90	9/30/2018	3208	EXPENSE REPORT	SEPT/2018	10/3/2018	HOLTON
238	3048	MARGARET D SCHREINER	Mileage	46.87	9/30/2018	3214	EXPENSE REPORT	SEPT/2018	10/3/2018	SCHREINER
239	3052	JAMES F SHELDON	Mileage	19.62	9/30/2018	3215	EXPENSE REPORT	SEPT/2018	10/3/2018	SHELDON
240	3227	JUDITH H KIMMES	Mileage	14.17	9/30/2018	3210	EXPENSE REPORT	SEPT/2018	10/3/2018	KIMMES
241	5426	PAUL A TRAPP	Mileage	107.91	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
242	5886	KENNETH H DANNER	Mileage	10.90	9/30/2018	3204	EXPENSE REPORT	SEPT/2018	10/3/2018	DANNER
243	7867	PAUL D R BAKKEN	Mileage	15.26	9/30/2018	3202	EXPENSE REPORT	SEPT/2018	10/3/2018	BAKKEN
244	8060	DAVID S JONES	Mileage	84.48	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
245	8207	JOHN D DEYOE	Mileage	141.70	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
246	2955	VICKI L AUBRECHT	Mileage	70.85	9/30/2018	361798	EXPENSE REPORT	SEP/2018	10/4/2018	EDU
247	4866	LINDA L LANDWEHR	Mileage	104.64	9/30/2018	361831	EXPENSE REPORT	SEP/2018	10/4/2018	POWSUP
248	4042	CRAIG TURNER	Mileage	89.93	9/30/2018	361935	EXPENSE REPORT	SEP/2018	10/9/2018	REG
249	4042	CRAIG TURNER	Mileage	50.14	9/30/2018	361935	EXPENSE REPORT	SEP/2018	10/9/2018	REGENGINEER
250	*4042*	*CRAIG TURNER*	*Mileage*	*24.53*	*9/30/2018*	*361935*	*EXPENSE REPORT*	*SEP/2018*	*10/9/2018*	*AGI2018*
251	*4042*	*CRAIG TURNER*	*Mileage*	*24.53*	*10/31/2018*	*361935*	*EXPENSE REPORT*	*OCT/2018*	*10/9/2018*	*AGI2018*
252	3818	JOE A MILLER	Mileage	9.81	10/31/2018	362138	EXPENSE REPORT	SEPT/2018	10/16/2018	ISSTEER
253	3818	JOE A MILLER	Mileage	14.17	10/31/2018	362138	EXPENSE REPORT	SEPT/2018	10/16/2018	MKT
254	3818	JOE A MILLER	Mileage	26.16	10/31/2018	362138	EXPENSE REPORT	SEPT/2018	10/16/2018	PUBREL
255	8872	PATRICK B MATHWIG	Mileage	10.90	10/31/2018	362345	EXPENSE REPORT	OCT/2018	10/23/2018	E3TRAIN
256	2899	MEHRHOFF, MALINDA R	Mileage	76.85	10/31/2018	362541	EXPENSE REPORT	OCT/2018	10/30/2018	EDU
257	4919	CLAY VAN DE BOGART	Mileage	20.17	10/31/2018	362565	EXPENSE REPORT	OCT/2018	10/30/2018	VAN
258	2305	GERALD F PITTMAN JR	Mileage	25.62	10/31/2018	3245	EXPENSE REPORT	OCT/2018	10/31/2018	PITTMAN
259	2625	JANET L LEKSON	Mileage	20.17	10/31/2018	3244	EXPENSE REPORT	OCT/2018	10/31/2018	LEKSON
260	3046	WILLIAM F HOLTON	Mileage	21.80	10/31/2018	3241	EXPENSE REPORT	OCT/2018	10/31/2018	HOLTON
261	3048	MARGARET D SCHREINER	Mileage	54.50	10/31/2018	3246	EXPENSE REPORT	OCT/2018	10/31/2018	SCHREINER
262	3052	JAMES F SHELDON	Mileage	37.06	10/31/2018	3247	EXPENSE REPORT	OCT/2018	10/31/2018	SHELDON
263	3227	JUDITH H KIMMES	Mileage	53.41	10/31/2018	3243	EXPENSE REPORT	OCT/2018	10/31/2018	KIMMES
264	5426	PAUL A TRAPP	Mileage	79.57	10/31/2018	3248	EXPENSE REPORT	OCT/2018	10/31/2018	PTRAPP
265	5886	KENNETH H DANNER	Mileage	26.16	10/31/2018	3238	EXPENSE REPORT	OCT/2018	10/31/2018	DANNER
266	7867	PAUL D R BAKKEN	Mileage	34.88	10/31/2018	3236	EXPENSE REPORT	OCT/2018	10/31/2018	BAKKEN
267	8060	DAVID S JONES	Mileage	19.62	10/31/2018	3242	EXPENSE REPORT	OCT/2018	10/31/2018	JONES

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
268	8207	JOHN D DEYOE	Mileage	45.78	10/31/2018	3239	EXPENSE REPORT	OCT/2018	10/31/2018	DEYOE
269	7816	TANYA S WOLFS	Mileage	27.25	10/31/2018	363085	EXPENSE REPORT	OCT/2018	11/8/2018	CIRC2018
270	7816	TANYA S WOLFS	Mileage	51.23	10/31/2018	363085	EXPENSE REPORT	OCT/2018	11/8/2018	MKT
271	7816	TANYA S WOLFS	Mileage	43.60	11/30/2018	363085	EXPENSE REPORT	NOV/2018	11/8/2018	POWSUP
272	3213	KIMBERLY A HELLESON	Mileage	50.14	10/31/2018	363163	EXPENSE REPORT	OCT-30-18	11/13/2018	EDU
273	3818	JOE A MILLER	Mileage	25.07	10/31/2018	363174	EXPENSE REPORT	OCT-29-18	11/13/2018	BRANDING
274	3818	JOE A MILLER	Mileage	9.81	10/31/2018	363174	EXPENSE REPORT	OCT-29-18	11/13/2018	MKT
275	3818	JOE A MILLER	Mileage	18.54	10/31/2018	363174	EXPENSE REPORT	OCT-29-18	11/13/2018	PUBREL
276	4042	CRAIG TURNER	Mileage	55.59	11/30/2018	363477	EXPENSE REPORT	NOV/2018	11/27/2018	REGENGINEER
277	4042	CRAIG TURNER	Mileage	57.23	11/30/2018	363477	EXPENSE REPORT	NOV/2018	11/27/2018	ETS
278	3226	US BANK	Mileage	11.00	11/30/2018	2009526	CC Recap-Jessica R. Klein	11/2018-JRK	11/30/2018	PUR
279	2899	MEHRHOFF, MALINDA R	Mileage	129.71	11/30/2018	363673	EXPENSE REPORT	NOV/2018	12/4/2018	EDU
280	2899	MEHRHOFF, MALINDA R	Mileage	11.99	11/30/2018	363673	EXPENSE REPORT	NOV/2018	12/4/2018	HIRE
281	3818	JOE A MILLER	Mileage	16.35	11/30/2018	363744	EXPENSE REPORT	NOV/2018	12/6/2018	PUBREL
282	4919	CLAY VAN DE BOGART	Mileage	66.50	11/30/2018	363764	EXPENSE REPORT	NOV/2018	12/6/2018	VAN
283	2305	GERALD F PITTMAN JR	Mileage	54.72	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
284	2625	JANET L LEKSON	Mileage	35.97	11/30/2018	3282	EXPENSE REPORT	NOV/2018	12/7/2018	LEKSON
285	3046	WILLIAM F HOLTON	Mileage	34.88	11/30/2018	3278	EXPENSE REPORT	NOV/2018	12/7/2018	HOLTON
286	3048	MARGARET D SCHREINER	Mileage	142.79	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
287	3052	JAMES F SHELDON	Mileage	61.59	11/30/2018	3286	EXPENSE REPORT	NOV/2018	12/7/2018	SHELDON
288	3227	JUDITH H KIMMES	Mileage	41.42	11/30/2018	3281	EXPENSE REPORT	NOV/2018	12/7/2018	KIMMES
289	5426	PAUL A TRAPP	Mileage	46.33	11/30/2018	3287	EXPENSE REPORT	NOV/2018	12/7/2018	PTRAPP
290	5886	KENNETH H DANNER	Mileage	10.90	11/30/2018	3275	EXPENSE REPORT	NOV/2018	12/7/2018	DANNER
291	7696	CHERRY A JORDAN	Mileage	17.17	11/30/2018	3280	EXPENSE REPORT	NOV/2018	12/7/2018	BOD
292	7867	PAUL D R BAKKEN	Mileage	15.26	11/30/2018	3274	EXPENSE REPORT	NOV/2018	12/7/2018	BAKKEN
293	8060	DAVID S JONES	Mileage	87.20	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
294	8207	JOHN D DEYOE	Mileage	100.83	11/30/2018	3276	EXPENSE REPORT	NOV/2018	12/7/2018	DEYOE
295	2908	DAVID S REINKE	Mileage	30.52	12/31/2018	364028	EXPENSE REPORT	DEC/2018	12/13/2018	E3TRAIN
296	2908	DAVID S REINKE	Mileage	42.51	12/31/2018	364028	EXPENSE REPORT	DEC/2018	12/13/2018	DSM
297	8545	COREY M HINTZ	Mileage	39.24	11/30/2018	3292	EXPENSE REPORT	NOV/2018	12/14/2018	POWSUP
298	4866	LINDA L LANDWEHR	Mileage	9.81	12/31/2018	364167	EXPENSE REPORT	DEC/2018	12/18/2018	MKTPLAN
299	4866	LINDA L LANDWEHR	Mileage	52.32	12/31/2018	364167	EXPENSE REPORT	DEC/2018	12/18/2018	E3TRAIN
300	4866	LINDA L LANDWEHR	Mileage	52.32	12/31/2018	364167	EXPENSE REPORT	DEC/2018	12/18/2018	POWSUP
301	4866	LINDA L LANDWEHR	Mileage	22.35	12/31/2018	364167	EXPENSE REPORT	DEC/2018	12/18/2018	COMMREL
302	2908	DAVID S REINKE	Mileage	81.75	12/31/2018	364328	EXPENSE REPORT	DEC/2018.2	12/20/2018	DSM
303	8872	PATRICK B MATHWIG	Mileage	1.09	12/31/2018	364316	EXPENSE REPORT	NOV/2018	12/20/2018	ELECCAR
304	8872	PATRICK B MATHWIG	Mileage	5.45	12/31/2018	364316	EXPENSE REPORT	NOV/2018	12/20/2018	AUDR
305	4919	CLAY VAN DE BOGART	Mileage	11.99	12/31/2018	364418	EXPENSE REPORT	DEC/2018	12/27/2018	VAN
306	8865	PATRICK M HUGHES	Mileage	305.20	12/31/2018	364390	EXPENSE REPORT	NOV/2018	12/27/2018	EDU
307	2305	GERALD F PITTMAN JR	Mileage	27.96	12/31/2018	3311	EXPENSE REPORT	DEC/2018	12/28/2018	PITTMAN
308	2625	JANET L LEKSON	Mileage	26.16	12/31/2018	3309	EXPENSE REPORT	DEC/2018	12/28/2018	LEKSON
309	3046	WILLIAM F HOLTON	Mileage	21.80	12/31/2018	3305	EXPENSE REPORT	DEC/2018	12/28/2018	HOLTON
310	3048	MARGARET D SCHREINER	Mileage	45.78	12/31/2018	3313	EXPENSE REPORT	DEC/2018	12/28/2018	SCHREINER
311	3052	JAMES F SHELDON	Mileage	44.69	12/31/2018	3314	EXPENSE REPORT	DEC/2018	12/28/2018	SHELDON
312	3227	JUDITH H KIMMES	Mileage	35.97	12/31/2018	3307	EXPENSE REPORT	DEC/2018	12/28/2018	KIMMES
313	5426	PAUL A TRAPP	Mileage	65.40	12/31/2018	3315	EXPENSE REPORT	DEC/2018	12/28/2018	PTRAPP
314	5886	KENNETH H DANNER	Mileage	10.90	12/31/2018	3302	EXPENSE REPORT	DEC/2018	12/28/2018	DANNER
315	7867	PAUL D R BAKKEN	Mileage	15.26	12/31/2018	3301	EXPENSE REPORT	DEC/2018	12/28/2018	BAKKEN
316	8060	DAVID S JONES	Mileage	73.58	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
317	8207	JOHN D DEYOE	Mileage	36.53	12/31/2018	3303	EXPENSE REPORT	DEC/2018	12/28/2018	DEYOE
318	2899	MEHRHOFF, MALINDA R	Mileage	28.34	12/31/2018	364443	EXPENSE REPORT	DEC/2018	1/3/2019	WELLNESS
319	3818	JOE A MILLER	Mileage	49.05	12/31/2018	364751	EXPENSE REPORT	DEC/2018	1/10/2019	PUBREL
320	3818	JOE A MILLER	Mileage	10.90	12/31/2018	364751	EXPENSE REPORT	DEC/2018	1/10/2019	BRANDING
321	8872	PATRICK B MATHWIG	Mileage	5.46	12/31/2018	364806	EXPENSE REPORT	DEC/2018	1/15/2019	ELECCAR

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
322	8872	PATRICK B MATHWIG	Mileage	1.64	12/31/2018	364806	EXPENSE REPORT	DEC/2018	1/15/2019	AUDR
323	8872	PATRICK B MATHWIG	Mileage	10.90	12/31/2018	364806	EXPENSE REPORT	DEC/2018	1/15/2019	E3TRAIN

Total Company - Mileage **$ 12,795.00**

324	3226	US BANK	Lodging	1,230.64	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
325	3226	US BANK	Lodging	99.11	1/31/2018	2009471	CC Recap-Michael D. Plutowski	1/2018-MDP	1/30/2018	DSM
326	3226	US BANK	Lodging	108.66	1/31/2018	2009471	CC Recap-Daniel P. Ross	1/2018-DPR	1/30/2018	VISITS
327	3226	US BANK	Lodging	198.22	1/31/2018	2009471	CC Recap-Tanya S. Wolfs	1/2018-TSW	1/30/2018	EDU
328	4042	CRAIG TURNER	Lodging	1,342.88	1/31/2018	356007	EXPENSE REPORT	JAN/2018	2/8/2018	EDU
329	2625	JANET L LEKSON	Lodging	902.16	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
330	3226	US BANK	Lodging	742.41	2/28/2018	2009471	CC Recap-Timothy J. Doherty	1/2018-TJD	1/30/2018	NETTECH
331	3226	US BANK	Lodging	195.96	2/28/2018	2009476	CC Recap-Glenda Hewitt	2/2018-GLH	3/1/2018	USO
332	3226	US BANK	Lodging	195.96	2/28/2018	2009476	CC Recap-Glenda Hewitt	2/2018-GLH	3/1/2018	USO
333	3226	US BANK	Lodging	195.96	2/28/2018	2009476	CC Recap-Glenda Hewitt	2/2018-GLH	3/1/2018	USO
334	3226	US BANK	Lodging	195.96	2/28/2018	2009476	CC Recap-Glenda Hewitt	2/2018-GLH	3/1/2018	USO
335	3226	US BANK	Lodging	832.40	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
336	3226	US BANK	Lodging	213.88	2/28/2018	2009476	CC Recap-Richard M. Siebenaler	2/2018-RMS	3/1/2018	EDU
337	3226	US BANK	Lodging	213.88	2/28/2018	2009476	CC Recap-Richard M. Siebenaler	2/2018-RMS	3/1/2018	EDU
338	3226	US BANK	Lodging	251.85	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
339	3226	US BANK	Lodging	832.40	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
340	3226	US BANK	Lodging	832.40	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
341	3226	US BANK	Lodging	94.82	2/28/2018	2009476	CC Recap-Randy D. Ratzlaff	2/2018-RDR	3/1/2018	EDU
342	3226	US BANK	Lodging	94.82	2/28/2018	2009476	CC Recap-Randy D. Ratzlaff	2/2018-RDR	3/1/2018	EDU
343	3226	US BANK	Lodging	94.82	2/28/2018	2009476	CC Recap-Randy D. Ratzlaff	2/2018-RDR	3/1/2018	EDU
344	3226	US BANK	Lodging	410.02	2/28/2018	2009476	CC Recap-Davin H. Peterson	2/2018-DHP	3/1/2018	ETS
345	3226	US BANK	Lodging	153.63	2/28/2018	2009476	CC Recap-Greg C. Miller	2/2018-GCM	3/1/2018	AMS
346	3226	US BANK	Lodging	99.50	2/28/2018	2009476	CC Recap-Greg C. Miller	2/2018-GCM	3/1/2018	AMS
347	8207	JOHN D DEYOE	Lodging	1,148.83	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
348	3226	US BANK	Lodging	290.88	3/31/2018	2009481	CC Recap-David J. Benkufsky	3/2018-DJB	3/29/2018	EDU
349	3226	US BANK	Lodging	638.88	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
350	3226	US BANK	Lodging	315.54	3/31/2018	2009481	CC Recap-Danielle J. Johnson	3/2018-DJJ	3/29/2018	EDU
351	3226	US BANK	Lodging	607.44	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	EDU
352	3226	US BANK	Lodging	115.31	3/31/2018	2009481	CC Recap-Greg C. Miller	3/2018-GCM	3/29/2018	AMS
353	3226	US BANK	Lodging	607.44	3/31/2018	2009481	CC Recap-Thomas E. Schmitz	3/2018-TES	3/29/2018	EDU
354	3226	US BANK	Lodging	607.44	3/31/2018	2009481	CC Recap-Jeffrey D Schultz	3/2018-JDS	3/29/2018	EDU
355	3226	US BANK	Lodging	330.09	3/31/2018	2009481	CC Recap-Tyler W. Kashdan	3/2018-TWK	3/29/2018	E3TRAIN
356	3226	US BANK	Lodging	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	3/2018-CCT	3/29/2018	EDU
357	3226	US BANK	Lodging	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	3/2018-CCT	3/29/2018	EDU
358	3226	US BANK	Lodging	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	3/2018-CCT	3/29/2018	EDU
359	4573	RICHARD W TEEGARDEN	Lodging	1,157.88	3/31/2018	356583	EXPENSE REPORT	MAR/2018	3/8/2018	EDU
360	5426	PAUL A TRAPP	Lodging	1,598.52	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
361	5886	KENNETH H DANNER	Lodging	115.31	3/31/2018	2982	EXPENSE REPORT	MAR/2018	3/28/2018	DANNER
362	8207	JOHN D DEYOE	Lodging	86.80	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
363	2625	JANET L LEKSON	Lodging	1,259.17	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
364	3226	US BANK	Lodging	905.37	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
365	3226	US BANK	Lodging	184.14	4/30/2018	2009486	CC Recap-Gregory D. Weber	4/2018-GDW	4/30/2018	EDU
366	3226	US BANK	Lodging	184.14	4/30/2018	2009486	CC Recap-Gregory D. Weber	4/2018-GDW	4/30/2018	EDU
367	*3226*	*US BANK*	*Lodging*	*623.92*	*5/31/2018*	*2009486*	*CC Recap-Grant S. Baumberger*	*4/2018-GSB*	*4/30/2018*	*AGI2018*
368	3226	US BANK	Lodging	775.77	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
369	3226	US BANK	Lodging	712.90	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
370	3226	US BANK	Lodging	725.76	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
371	3226	US BANK	Lodging	438.40	6/30/2018	2009486	CC Recap-Tanya S. Wolfs	4/2018-TSW	4/30/2018	EDU

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
372	3226	US BANK	Lodging	471.52	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
373	3226	US BANK	Lodging	729.63	6/30/2018	2009496	CC Recap-Grant S. Baumberger	6/2018-GSB	7/2/2018	EDU
374	5426	PAUL A TRAPP	Lodging	149.21	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
375	8826	GRAND VIEW LODGE	Lodging	351.12	6/30/2018	357229	CONF LODGING-M LOFTHUS	2018-EDAM	4/17/2018	ECO
376	337	MN RURAL ELECTRIC ASSOCIATION	Lodging	4,312.70	7/31/2018	360874	2018 YOUTH TOUR EXP	INV00013571	8/28/2018	YOUTH
377	3226	US BANK	Lodging	362.38	7/31/2018	2009490	CC Recap-Lou Ann D. Weflen	5/2018-LAW	5/31/2018	WCOMP
378	3226	US BANK	Lodging	528.76	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
379	3226	US BANK	Lodging	70.12	7/31/2018	2009501	CC Recap-Douglas R. Larson	7/2018-DRL	7/31/2018	POWSUP
380	3226	US BANK	Lodging	192.28	7/31/2018	2009501	CC Recap-Douglas R. Larson	7/2018-DRL	7/31/2018	POWSUP
381	3226	US BANK	Lodging	237.09	7/31/2018	2009501	CC Recap-Mark W. Lofthus	7/2018-MWL	7/31/2018	ECO
382	3226	US BANK	Lodging	70.12	7/31/2018	2009501	CC Recap-Greg C. Miller	7/2018-GCM	7/31/2018	AMS
383	3226	US BANK	Lodging	192.28	7/31/2018	2009501	CC Recap-Greg C. Miller	7/2018-GCM	7/31/2018	AMS
384	3226	US BANK	Lodging	(73.48)	7/31/2018	2009501	CC Recap-Tanya S. Wolfs	7/2018-TSW	7/31/2018	EDU
385	3226	US BANK	Lodging	528.76	7/31/2018	2009501	CC Recap-Joseph A. Miller	7/2018-JAM	7/31/2018	BRANDING
386	3226	US BANK	Lodging	351.12	7/31/2018	2009501	CC Recap-Margaret (Peggy) P Jo	7/2018-PPJ	7/31/2018	COMMREL
387	3226	US BANK	Lodging	514.15	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
388	2625	JANET L LEKSON	Lodging	198.22	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
389	2938	HENKE, CARLA S	Lodging	204.96	8/31/2018	3165	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
390	3226	US BANK	Lodging	220.13	8/31/2018	2009501	CC Recap-Randy D. Ratzlaff	7/2018-RDR	7/31/2018	EDU
391	3226	US BANK	Lodging	220.13	8/31/2018	2009501	CC Recap-Randy D. Ratzlaff	7/2018-RDR	7/31/2018	MLT
392	3226	US BANK	Lodging	220.13	8/31/2018	2009501	CC Recap-Randy D. Ratzlaff	7/2018-RDR	7/31/2018	MLT
393	3226	US BANK	Lodging	200.00	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	AMS
394	3226	US BANK	Lodging	1,140.41	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
395	3226	US BANK	Lodging	293.65	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
396	3226	US BANK	Lodging	428.00	8/31/2018	2009507	CC Recap-Joseph P. Kuhn	8/2018-JPK	8/30/2018	USO
397	3226	US BANK	Lodging	231.75	8/31/2018	2009507	CC Recap-Randy D. Ratzlaff	8/2018-RDR	8/30/2018	EDU
398	3226	US BANK	Lodging	231.75	8/31/2018	2009507	CC Recap-Randy D. Ratzlaff	8/2018-RDR	8/30/2018	EDU
399	3226	US BANK	Lodging	231.75	8/31/2018	2009507	CC Recap-Randy D. Ratzlaff	8/2018-RDR	8/30/2018	EDU
400	5426	PAUL A TRAPP	Lodging	198.22	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
401	5886	KENNETH H DANNER	Lodging	198.22	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
402	8060	DAVID S JONES	Lodging	99.11	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
403	8545	COREY M HINTZ	Lodging	393.54	8/31/2018	3166	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
404	2625	JANET L LEKSON	Lodging	686.50	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
405	2938	HENKE, CARLA S	Lodging	1,236.39	9/30/2018	3207	EXPENSE REPORT	SEP/2018	10/3/2018	LAWSON
406	3226	US BANK	Lodging	110.32	9/30/2018	2009512	CC Recap-Kevin S. Fowler	9/2018-KSF	10/1/2018	SAF
407	3226	US BANK	Lodging	222.91	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	PTRAPP
408	3226	US BANK	Lodging	598.76	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
409	3226	US BANK	Lodging	109.88	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
410	3226	US BANK	Lodging	190.16	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	DSM
411	*3226*	*US BANK*	*Lodging*	*306.45*	*9/30/2018*	*2009512*	*CC Recap-Craig C. Turner*	*9/2018-CCT*	*10/1/2018*	*AGI2018*
412	5426	PAUL A TRAPP	Lodging	222.89	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
413	8060	DAVID S JONES	Lodging	153.63	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
414	8207	JOHN D DEYOE	Lodging	307.26	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
415	3226	US BANK	Lodging	335.13	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
416	3226	US BANK	Lodging	332.52	10/31/2018	2009520	CC Recap-Jeffrey D Schultz	10/2018-JDS	10/31/2018	EDU
417	*3226*	*US BANK*	*Lodging*	*437.05*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
418	3226	US BANK	Lodging	332.52	10/31/2018	2009520	CC Recap-Corey S. Willert	10/2018-CSW	10/31/2018	EDU
419	3226	US BANK	Lodging	437.05	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
420	*3226*	*US BANK*	*Lodging*	*1,624.17*	*10/31/2018*	*2009520*	*CC Recap-Craig C. Turner*	*10/2018-CCT*	*10/31/2018*	*AGI2018*
421	2305	GERALD F PITTMAN JR	Lodging	945.00	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
422	3048	MARGARET D SCHREINER	Lodging	945.00	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
423	3226	US BANK	Lodging	1,111.80	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
424	3226	US BANK	Lodging	111.15	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
425	7138	GERI L WACHTER	Lodging	236.96	11/30/2018	3123	EXPENSE REPORT	JULY/2018	7/25/2018	TIMETRACK

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
426	7138	GERI L WACHTER	Lodging	801.60	11/30/2018	3264	EXPENSE REPORT	NOV/2018	11/21/2018	TIMETRACK
427	8060	DAVID S JONES	Lodging	945.00	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
428	3226	US BANK	Lodging	459.30	12/31/2018	2009534	CC Recap-Michael G. Fosse	12/2018-MGF	12/31/2018	ACS
429	3226	US BANK	Lodging	221.52	12/31/2018	2009534	CC Recap-Kevin S. Fowler	12/2018-KSF	12/31/2018	EDU
430	3226	US BANK	Lodging	375.00	12/31/2018	2009534	CC Recap-Patrick M Hughes	12/2018-PMH	12/31/2018	EDU
431	3226	US BANK	Lodging	221.89	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
432	3226	US BANK	Lodging	708.75	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	REG
433	3226	US BANK	Lodging	153.63	12/31/2018	2009534	CC Recap-Greg C. Miller	12/2018-GCM	12/31/2018	AMS
434	3226	US BANK	Lodging	110.63	12/31/2018	2009534	CC Recap-Daniel P. Ross	12/2018-DPR	12/31/2018	VISITS

Total Company - Lodging **$ 52,290.36**

435	3226	US BANK	Other Travel	49.20	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
436	3226	US BANK	Other Travel	53.40	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
437	3226	US BANK	Other Travel	61.38	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
438	3226	US BANK	Other Travel	5.00	1/31/2018	2009471	CC Recap-Jane E. Siebenaler	1/2018-JES	1/30/2018	VISITS
439	3226	US BANK	Other Travel	3.00	1/31/2018	2009471	CC Recap-Lou Ann D. Weflen	1/2018-LAW	1/30/2018	WCOMP
440	3838	MILLER, GREG C	Other Travel	108.25	1/31/2018	355773	EXPENSE REPORT	JAN/2018-EX	1/30/2018	AMS
441	4042	CRAIG TURNER	Other Travel	30.00	1/31/2018	356007	EXPENSE REPORT	JAN/2018	2/8/2018	EDU
442	2305	GERALD F PITTMAN JR	Other Travel	10.25	2/28/2018	2953	EXPENSE REPORT	FEB/2018	2/28/2018	PITTMAN
443	2625	JANET L LEKSON	Other Travel	122.68	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
444	2895	DOUGLAS R LARSON	Other Travel	24.00	2/28/2018	2961	EXPENSE REPORT	FEB/2018	3/7/2018	REG
445	2895	DOUGLAS R LARSON	Other Travel	11.00	2/28/2018	2961	EXPENSE REPORT	FEB/2018	3/7/2018	LEGIS
446	2955	VICKI L AUBRECHT	Other Travel	45.00	2/28/2018	356493	EXPENSE REPORT	FEB/2018	3/6/2018	IFS
447	3048	MARGARET D SCHREINER	Other Travel	5.00	2/28/2018	2955	EXPENSE REPORT	FEB/2018	2/28/2018	SCHREINER
448	3226	US BANK	Other Travel	165.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	PTRAPP
449	3226	US BANK	Other Travel	110.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	DEYOE
450	3226	US BANK	Other Travel	60.00	2/28/2018	2009471	CC Recap-Danielle J. Johnson	1/2018-DJJ	1/30/2018	EDU
451	3226	US BANK	Other Travel	36.41	2/28/2018	2009476	CC Recap-Michael G. Fosse	2/2018-MGF	3/1/2018	ACS
452	3226	US BANK	Other Travel	60.00	2/28/2018	2009476	CC Recap-Danielle J. Johnson	2/2018-DJJ	3/1/2018	EDU
453	3226	US BANK	Other Travel	10.00	2/28/2018	2009476	CC Recap-Stephanie M. Pederson	2/2018-SMP	3/1/2018	FAIRSHOW
454	3226	US BANK	Other Travel	20.97	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
455	3226	US BANK	Other Travel	3.00	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
456	3226	US BANK	Other Travel	5.95	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
457	3226	US BANK	Other Travel	48.00	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
458	3226	US BANK	Other Travel	63.00	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
459	3226	US BANK	Other Travel	63.00	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
460	3226	US BANK	Other Travel	96.55	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
461	3226	US BANK	Other Travel	23.00	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	EDU
462	3226	US BANK	Other Travel	100.00	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	EDU
463	3226	US BANK	Other Travel	120.00	2/28/2018	2009476	CC Recap-Craig C. Turner	2/2018-CCT	3/1/2018	EDU
464	4573	RICHARD W TEEGARDEN	Other Travel	271.80	2/28/2018	356583	EXPENSE REPORT	FEB/2018-2	3/8/2018	EDU
465	8207	JOHN D DEYOE	Other Travel	11.00	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
466	2305	GERALD F PITTMAN JR	Other Travel	10.00	3/31/2018	2993	EXPENSE REPORT	MAR/2018	3/28/2018	PITTMAN
467	2895	DOUGLAS R LARSON	Other Travel	18.00	3/31/2018	3001	EXPENSE REPORT	MAR/2018	4/4/2018	REG
468	2908	DAVID S REINKE	Other Travel	7.50	3/31/2018	356912	EXPENSE REPORT	MAR/2018	3/27/2018	DSM
469	3048	MARGARET D SCHREINER	Other Travel	11.00	3/31/2018	2994	EXPENSE REPORT	MAR/2018	3/28/2018	SCHREINER
470	3226	US BANK	Other Travel	39.99	3/31/2018	2009481	CC Recap-David J. Benkufsky	3/2018-DJB	3/29/2018	EDU
471	3226	US BANK	Other Travel	11.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
472	3226	US BANK	Other Travel	42.85	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
473	3226	US BANK	Other Travel	32.50	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
474	3226	US BANK	Other Travel	11.00	3/31/2018	2009481	CC Recap-Margaret (Peggy) P. J	3/2018-PPJ	3/29/2018	COMMREL
475	3226	US BANK	Other Travel	35.00	3/31/2018	2009481	CC Recap-Douglas R. Larson	3/2018-DRL	3/29/2018	REG
476	3226	US BANK	Other Travel	10.00	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
477	3226	US BANK	Other Travel	20.00	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO
478	3226	US BANK	Other Travel	6.00	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO
479	3226	US BANK	Other Travel	230.26	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	EDU
480	3226	US BANK	Other Travel	96.00	3/31/2018	2009481	CC Recap-Thomas E. Schmitz	3/2018-TES	3/29/2018	EDU
481	3226	US BANK	Other Travel	8.00	3/31/2018	2009481	CC Recap-Jeffrey L. Schoenecke	3/2018-JLS	3/29/2018	ETS
482	3226	US BANK	Other Travel	247.03	3/31/2018	2009481	CC Recap-Jeffrey D Schultz	3/2018-JDS	3/29/2018	EDU
483	5426	PAUL A TRAPP	Other Travel	118.00	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
484	8207	JOHN D DEYOE	Other Travel	10.00	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
485	8568	JAMES R STENSTROM	Other Travel	9.00	3/31/2018	357075	EXPENSE REPORT	FEB/2018	4/5/2018	EDU
486	8650	STEPHANIE M PEDERSON	Other Travel	24.00	3/31/2018	356957	EXPENSE REPORT	MAR/2018	3/29/2018	ELECCAR
487	8704	THOMAS L COAKLEY	Other Travel	45.00	3/31/2018	356652	EXPENSE REPORT	FEB/2018	3/13/2018	EDU
488	2625	JANET L LEKSON	Other Travel	88.47	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
489	2895	DOUGLAS R LARSON	Other Travel	7.50	4/30/2018	3046	EXPENSE REPORT	APR/2018	5/9/2018	REG
490	2933	MARGARET P JOHNSON	Other Travel	6.00	4/30/2018	3045	EXPENSE REPORT	APR/2018	5/9/2018	COMMREL
491	3226	US BANK	Other Travel	8.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	4/2018-DRL	4/30/2018	LEGIS
492	3226	US BANK	Other Travel	13.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	4/2018-DRL	4/30/2018	LEGIS
493	3226	US BANK	Other Travel	6.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	4/2018-DRL	4/30/2018	LEGIS
494	3226	US BANK	Other Travel	20.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
495	3226	US BANK	Other Travel	25.26	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
496	3226	US BANK	Other Travel	26.78	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
497	3226	US BANK	Other Travel	75.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
498	3226	US BANK	Other Travel	9.00	4/30/2018	2009486	CC Recap-Malinda R. Mehrhoff	4/2018-MRM-6676	4/30/2018	HRP
499	3226	US BANK	Other Travel	10.00	4/30/2018	2009486	CC Recap-Greg C. Miller	4/2018-GCM	4/30/2018	AMS
500	3226	US BANK	Other Travel	11.00	4/30/2018	2009486	CC Recap-Greg C. Miller	4/2018-GCM	4/30/2018	AMS
501	3226	US BANK	Other Travel	8.00	4/30/2018	2009486	CC Recap-Joseph A. Miller	4/2018-JAM	4/30/2018	BRANDING
502	3226	US BANK	Other Travel	10.00	4/30/2018	2009486	CC Recap-Stephanie M. Pederson	4/2018-SMP	4/30/2018	ELECCAR
503	3226	US BANK	Other Travel	5.00	4/30/2018	2009486	CC Recap-Stephanie M. Pederson	4/2018-SMP	4/30/2018	E3TRAIN
504	3226	US BANK	Other Travel	5.00	4/30/2018	2009486	CC Recap-Stephanie M. Pederson	4/2018-SMP	4/30/2018	E3TRAIN
505	3226	US BANK	Other Travel	12.00	4/30/2018	2009486	CC Recap-Michael D. Plutowski	4/2018-MDP	4/30/2018	DSM
506	3226	US BANK	Other Travel	10.00	4/30/2018	2009486	CC Recap-Michael D. Plutowski	4/2018-MDP	4/30/2018	DSM
507	3226	US BANK	Other Travel	7.00	4/30/2018	2009486	CC Recap-David S. Reinke	4/2018-DSR	4/30/2018	DSM
508	3226	US BANK	Other Travel	52.50	4/30/2018	2009486	CC Recap-Jeffrey L. Schoenecke	4/2018-JLS	4/30/2018	EDU
509	3226	US BANK	Other Travel	51.92	4/30/2018	2009486	CC Recap-Jeffrey L. Schoenecke	4/2018-JLS	4/30/2018	EDU
510	3226	US BANK	Other Travel	62.50	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
511	3226	US BANK	Other Travel	65.08	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
512	3226	US BANK	Other Travel	43.20	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
513	3226	US BANK	Other Travel	117.00	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
514	5426	PAUL A TRAPP	Other Travel	7.13	4/30/2018	3039	EXPENSE REPORT	APR/2018	5/1/2018	PTRAPP
515	8207	JOHN D DEYOE	Other Travel	72.90	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
516	2895	DOUGLAS R LARSON	Other Travel	26.00	5/31/2018	3065	EXPENSE REPORT	MAY/2018	6/6/2018	REG
517	3226	US BANK	Other Travel	8.00	5/31/2018	2009490	CC Recap-Douglas R. Larson	5/2018-DRL	5/31/2018	POWSUP
518	3226	US BANK	Other Travel	36.00	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
519	3226	US BANK	Other Travel	7.00	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
520	3226	US BANK	Other Travel	8.00	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
521	3226	US BANK	Other Travel	8.00	5/31/2018	2009490	CC Recap-Stephanie M. Pederson	5/2018-SMP	5/31/2018	DSM
522	3226	US BANK	Other Travel	10.00	5/31/2018	2009490	CC Recap-Michael D. Plutowski	5/2018-MDP	5/31/2018	DSM
523	3226	US BANK	Other Travel	52.51	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
524	3226	US BANK	Other Travel	30.00	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
525	3226	US BANK	Other Travel	25.00	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
526	3226	US BANK	Other Travel	25.00	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
527	3226	US BANK	Other Travel	20.00	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
528	3226	US BANK	Other Travel	9.00	5/31/2018	2009490	CC Recap-Betty Jo A. Kiesow	5/2018-BAK	5/31/2018	EDU
529	3226	US BANK	Other Travel	9.00	5/31/2018	2009490	CC Recap-Betty Jo A. Kiesow	5/2018-BAK	5/31/2018	EDU
530	3226	US BANK	Other Travel	10.00	5/31/2018	2009490	CC Recap-Greg C. Miller	5/2018-GCM	5/31/2018	AMS

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
531	3226	US BANK	Other Travel	7.50	5/31/2018	2009490	CC Recap-Michael R. Nelson	5/2018-MRN	5/31/2018	IFS
532	3226	US BANK	Other Travel	40.20	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
533	3226	US BANK	Other Travel	57.00	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
534	3226	US BANK	Other Travel	39.10	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
535	3226	US BANK	Other Travel	25.00	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
536	*3226*	*US BANK*	*Other Travel*	*11.00*	*5/31/2018*	*2009490*	*CC Recap-Craig C. Turner*	*5/2018-CCT*	*5/31/2018*	*AGI2018*
537	3226	US BANK	Other Travel	8.00	5/31/2018	2009490	CC Recap-Craig C. Turner	5/2018-CCT	5/31/2018	REGENGINEER
538	8165	MARK W LOFTHUS	Other Travel	51.30	5/31/2018	358588	EXPENSE REPORT	MAY/2018	6/7/2018	ECO
539	2895	DOUGLAS R LARSON	Other Travel	13.00	6/30/2018	3111	EXPENSE REPORT	JUNE/2018	7/11/2018	REG
540	3226	US BANK	Other Travel	1.00	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-1109	7/2/2018	EDU
541	3226	US BANK	Other Travel	1.00	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-1109	7/2/2018	EDU
542	3226	US BANK	Other Travel	1.00	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-6676	7/2/2018	EDU
543	3226	US BANK	Other Travel	36.00	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
544	3226	US BANK	Other Travel	8.50	6/30/2018	2009496	CC Recap-Jeffrey L. Schoenecke	6/2018-JLS	7/2/2018	ETS
545	3226	US BANK	Other Travel	39.25	6/30/2018	2009496	CC Recap-Jeffrey L. Schoenecke	6/2018-JLS	7/2/2018	AUO
546	3226	US BANK	Other Travel	8.00	6/30/2018	2009496	CC Recap-Craig C. Turner	6/2018-CCT	7/2/2018	REGENGINEER
547	*3226*	*US BANK*	*Other Travel*	*25.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
548	*3226*	*US BANK*	*Other Travel*	*25.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
549	337	MN RURAL ELECTRIC ASSOCIATION	Other Travel	3,096.30	7/31/2018	360874	2018 YOUTH TOUR EXP	INV00013571	8/28/2018	YOUTH
550	2895	DOUGLAS R LARSON	Other Travel	12.00	7/31/2018	3147	EXPENSE REPORT	JULY/2018	8/8/2018	REG
551	3226	US BANK	Other Travel	39.64	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
552	3226	US BANK	Other Travel	75.72	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
553	3226	US BANK	Other Travel	9.00	7/31/2018	2009501	CC Recap-Malinda R. Mehrhoff	7/2018-MRM-6676	7/31/2018	EDU
554	3226	US BANK	Other Travel	9.00	7/31/2018	2009501	CC Recap-Malinda R. Mehrhoff	7/2018-MRM-6676	7/31/2018	EDU
555	3226	US BANK	Other Travel	51.49	7/31/2018	2009501	CC Recap-Joseph A. Miller	7/2018-JAM	7/31/2018	BRANDING
556	3226	US BANK	Other Travel	125.40	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
557	3226	US BANK	Other Travel	48.22	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
558	3226	US BANK	Other Travel	10.69	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	7/2018-JLS	7/31/2018	AUO
559	3226	US BANK	Other Travel	23.33	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	7/2018-JLS	7/31/2018	AUO
560	2890	KIESOW, BETTY JO A	Other Travel	14.00	8/31/2018	3182	EXPENSE REPORT	AUG/2018	9/6/2018	LOC
561	3226	US BANK	Other Travel	16.00	8/31/2018	2009507	CC Recap-Margaret (Peggy) P Jo	8/2018-PPJ	8/30/2018	COMMREL
562	3226	US BANK	Other Travel	8.00	8/31/2018	2009507	CC Recap-Craig Knudsen	8/2018-CEK	8/30/2018	EDU
563	3226	US BANK	Other Travel	6.00	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
564	3226	US BANK	Other Travel	7.00	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
565	3226	US BANK	Other Travel	35.12	8/31/2018	2009507	CC Recap-Jeffrey L Schoenecker	8/2018-JLS	8/30/2018	AUO
566	3226	US BANK	Other Travel	5.00	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
567	3226	US BANK	Other Travel	14.55	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
568	3226	US BANK	Other Travel	29.00	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
569	3226	US BANK	Other Travel	32.16	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
570	3226	US BANK	Other Travel	5.00	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
571	3227	JUDITH H KIMMES	Other Travel	2.00	8/31/2018	3175	EXPENSE REPORT	AUG/2018	9/4/2018	KIMMES
572	2625	JANET L LEKSON	Other Travel	40.47	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
573	2895	DOUGLAS R LARSON	Other Travel	22.00	9/30/2018	3224	EXPENSE REPORT	SEP/2018	10/12/2018	REG
574	2908	DAVID S REINKE	Other Travel	50.00	9/30/2018	361989	EXPENSE REPORT	SEP/2018	10/11/2018	DSM
575	2938	HENKE, CARLA S	Other Travel	152.21	9/30/2018	3207	EXPENSE REPORT	SEP/2018	10/3/2018	LAWSON
576	3226	US BANK	Other Travel	25.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
577	3226	US BANK	Other Travel	93.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
578	3226	US BANK	Other Travel	27.44	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
579	3226	US BANK	Other Travel	10.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
580	3226	US BANK	Other Travel	45.69	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
581	3226	US BANK	Other Travel	5.20	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
582	3226	US BANK	Other Travel	39.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
583	3226	US BANK	Other Travel	10.00	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
584	3226	US BANK	Other Travel	40.44	9/30/2018	2009512	CC Recap-Jeffrey L Schoenecker	9/2018-JLS	10/1/2018	AUO

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
585	3226	US BANK	Other Travel	30.00	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	EDU
586	3226	US BANK	Other Travel	30.00	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	EDU
587	3226	US BANK	Other Travel	8.00	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	DSM
588	3226	US BANK	Other Travel	3.00	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	DSM
589	3226	US BANK	Other Travel	13.00	9/30/2018	2009512	CC Recap-Craig C. Turner	9/2018-CCT	10/1/2018	REG
590	5426	PAUL A TRAPP	Other Travel	28.00	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
591	8060	DAVID S JONES	Other Travel	15.00	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
592	3226	US BANK	Other Travel	6.50	10/31/2018	2009520	CC Recap-Michael G. Fosse	10/2018-MGF	10/31/2018	ACS
593	3226	US BANK	Other Travel	37.02	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
594	3226	US BANK	Other Travel	34.33	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
595	3226	US BANK	Other Travel	(18.51)	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
596	3226	US BANK	Other Travel	19.60	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
597	*3226*	*US BANK*	*Other Travel*	*8.00*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
598	*3226*	*US BANK*	*Other Travel*	*218.26*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
599	*3226*	*US BANK*	*Other Travel*	*57.00*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
600	*3226*	*US BANK*	*Other Travel*	*12.08*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
601	3226	US BANK	Other Travel	8.50	10/31/2018	2009520	CC Recap-Craig C. Turner	10/2018-CCT	10/31/2018	REG
602	3226	US BANK	Other Travel	8.00	10/31/2018	2009520	CC Recap-Craig C. Turner	10/2018-CCT	10/31/2018	REG
603	*3226*	*US BANK*	*Other Travel*	*105.00*	*10/31/2018*	*2009520*	*CC Recap-Craig C. Turner*	*10/2018-CCT*	*10/31/2018*	*AGI2018*
604	*4042*	*CRAIG TURNER*	*Other Travel*	*305.43*	*10/31/2018*	*361935*	*EXPENSE REPORT*	*OCT/2018*	*10/9/2018*	*AGI2018*
605	2305	GERALD F PITTMAN JR	Other Travel	9.75	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
606	2767	JANE E SIEBENALER	Other Travel	9.46	11/30/2018	363416	EXPENSE REPORT	OCT/2018	11/20/2018	EDU
607	2767	JANE E SIEBENALER	Other Travel	21.51	11/30/2018	363416	EXPENSE REPORT	NOV/2018	11/20/2018	EDU
608	2895	DOUGLAS R LARSON	Other Travel	97.81	11/30/2018	3273	EXPENSE REPORT	NOV/2018	12/4/2018	REG
609	3048	MARGARET D SCHREINER	Other Travel	377.84	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
610	3226	US BANK	Other Travel	31.06	11/30/2018	2009526	CC Recap-Michael G. Fosse	11/2018-MGF	11/30/2018	ACS
611	3226	US BANK	Other Travel	10.00	11/30/2018	2009526	CC Recap-Michael G. Fosse	11/2018-MGF	11/30/2018	ACS
612	3226	US BANK	Other Travel	17.00	11/30/2018	2009526	CC Recap-Michael G. Fosse	11/2018-MGF	11/30/2018	COMMREL
613	3226	US BANK	Other Travel	7.00	11/30/2018	2009526	CC Recap-Malinda R. Mehrhoff	11/2018-MRM-6676	11/30/2018	EDU
614	3226	US BANK	Other Travel	14.00	11/30/2018	2009526	CC Recap-Malinda R. Mehrhoff	11/2018-MRM-6676	11/30/2018	EDU
615	3226	US BANK	Other Travel	105.00	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
616	3226	US BANK	Other Travel	10.00	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	EDU
617	3226	US BANK	Other Travel	10.00	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	EDU
618	3226	US BANK	Other Travel	12.25	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	REG
619	3226	US BANK	Other Travel	10.00	11/30/2018	2009526	CC Recap-Jeffrey L Schoenecker	11/2018-JLS	11/30/2018	AUO
620	3226	US BANK	Other Travel	3.00	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
621	3226	US BANK	Other Travel	10.00	11/30/2018	2009526	CC Recap-Davin H. Peterson	11/2018-DHP	11/30/2018	EDU
622	7138	GERI L WACHTER	Other Travel	64.60	11/30/2018	3264	EXPENSE REPORT	NOV/2018	11/21/2018	TIMETRACK
623	8060	DAVID S JONES	Other Travel	54.17	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
624	2600	ANIXTER WIRE & CABLE	Other Travel	218.15	12/31/2018	364423		4079889-00	1/3/2019	AGIADMIN
625	2895	DOUGLAS R LARSON	Other Travel	95.00	12/31/2018	3320	EXPENSE REPORT	DEC/2018	1/9/2019	AMS
626	2933	MARGARET P JOHNSON	Other Travel	39.00	12/31/2018	3317	EXPENSE REPORT	DEC/2018	1/4/2019	COMMREL
627	3226	US BANK	Other Travel	27.95	12/31/2018	2009534	CC Recap-Michael G. Fosse	12/2018-MGF	12/31/2018	ACS
628	3226	US BANK	Other Travel	10.70	12/31/2018	2009534	CC Recap-Michael G. Fosse	12/2018-MGF	12/31/2018	ACS
629	3226	US BANK	Other Travel	44.40	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
630	3226	US BANK	Other Travel	39.10	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
631	3226	US BANK	Other Travel	9.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
632	3226	US BANK	Other Travel	10.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
633	3226	US BANK	Other Travel	6.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
634	3226	US BANK	Other Travel	3.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
635	3226	US BANK	Other Travel	48.00	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
636	3226	US BANK	Other Travel	5.00	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	REG
637	3226	US BANK	Other Travel	9.00	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	REG
638	8060	DAVID S JONES	Other Travel	5.00	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES

Travel Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
		Total Company - Other Travel		**$ 10,960.60**						
		Total Company Travel		**$ 97,508.97**						
		AGI2018	*Airfare*	*760.20*						
			Mileage	*49.06*						
			Lodging	*2,991.59*						
			Other Travel	*766.77*						
		Total AGI2018 Excluded		*4,567.62*						
		Total Company Travel without AGI2018		**$ 92,941.35**						

Workpaper 15B
Meal Expenses

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1	2625	JANET L LEKSON	Meals	28.71	1/31/2018	2914	EXPENSE REPORT	JAN/2018	1/31/2018	LEKSON
2	3048	MARGARET D SCHREINER	Meals	35.79	1/31/2018	2916	EXPENSE REPORT	JAN/2018	1/31/2018	SCHREINER
3	3226	US BANK	Meals	97.95	1/31/2018	2009471	CC Recap-Denise D. Hrncir	1/2018-DDH	1/30/2018	WELLNESS
4	3226	US BANK	Meals	35.18	1/31/2018	2009471	CC Recap-Denise D. Hrncir	1/2018-DDH	1/30/2018	HRP
5	3226	US BANK	Meals	31.67	1/31/2018	2009471	CC Recap-Michael G. Fosse	1/2018-MGF	1/30/2018	ACS
6	3226	US BANK	Meals	32.90	1/31/2018	2009471	CC Recap-Cherry A. Jordan	1/2018-CAJ	1/30/2018	BOD
7	3226	US BANK	Meals	26.67	1/31/2018	2009471	CC Recap-Cherry A. Jordan	1/2018-CAJ	1/30/2018	BOD
8	3226	US BANK	Meals	33.28	1/31/2018	2009471	CC Recap-Cherry A. Jordan	1/2018-CAJ	1/30/2018	BOD
9	3226	US BANK	Meals	165.44	1/31/2018	2009471	CC Recap-Brenda K. Kadlec	1/2018-BKK	1/30/2018	ACS
10	3226	US BANK	Meals	32.00	1/31/2018	2009471	CC Recap-Tyler W. Kashdan	1/2018-TWK	1/30/2018	DSM
11	3226	US BANK	Meals	30.66	1/31/2018	2009471	CC Recap-Glenda Hewitt	1/2018-GLH	1/30/2018	STA
12	3226	US BANK	Meals	138.07	1/31/2018	2009471	CC Recap-Betty Jo A. Kiesow	1/2018-BAK	1/30/2018	NCD
13	3226	US BANK	Meals	290.27	1/31/2018	2009471	CC Recap-Ann J. Maniaci	1/2018-AJM	1/30/2018	SAFCIT2
14	3226	US BANK	Meals	57.12	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
15	3226	US BANK	Meals	69.82	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
16	3226	US BANK	Meals	71.42	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
17	3226	US BANK	Meals	338.00	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
18	3226	US BANK	Meals	61.34	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
19	3226	US BANK	Meals	6.95	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
20	3226	US BANK	Meals	51.66	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
21	3226	US BANK	Meals	145.01	1/31/2018	2009471	CC Recap-Greg C. Miller	1/2018-GCM	1/30/2018	AMS
22	3226	US BANK	Meals	29.94	1/31/2018	2009471	CC Recap-Anthony J. Nobach	1/2018-AJN	1/30/2018	DIS
23	3226	US BANK	Meals	22.44	1/31/2018	2009471	CC Recap-Anthony J. Nobach	1/2018-AJN	1/30/2018	DIS
24	3226	US BANK	Meals	17.29	1/31/2018	2009471	CC Recap-Daniel P. Ross	1/2018-DPR	1/30/2018	VISITS
25	3226	US BANK	Meals	45.08	1/31/2018	2009471	CC Recap-Daniel P. Ross	1/2018-DPR	1/30/2018	VISITS
26	3226	US BANK	Meals	40.00	1/31/2018	2009471	CC Recap-Richard M. Siebenaler	1/2018-RMS	1/30/2018	USO
27	3226	US BANK	Meals	156.11	1/31/2018	2009471	CC Recap-Julie A. Simonsen	1/2018-JAS	1/30/2018	EFUNC
28	*3226*	*US BANK*	*Meals*	*48.63*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
29	*3226*	*US BANK*	*Meals*	*29.60*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
30	*3226*	*US BANK*	*Meals*	*11.99*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
31	3226	US BANK	Meals	30.38	1/31/2018	2009471	CC Recap-Timothy J. Doherty	1/2018-TJD	1/30/2018	VISITS
32	3226	US BANK	Meals	75.65	1/31/2018	2009471	CC Recap-Timothy J. Doherty	1/2018-TJD	1/30/2018	VISITS
33	3226	US BANK	Meals	56.60	1/31/2018	2009471	CC Recap-Corey S. Willert	1/2018-CSW	1/30/2018	NCD
34	3226	US BANK	Meals	17.11	1/31/2018	2009471	CC Recap-Tanya S. Wolfs	1/2018-TSW	1/30/2018	EDU
35	3226	US BANK	Meals	6.56	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
36	3226	US BANK	Meals	25.00	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
37	3226	US BANK	Meals	25.00	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
38	3226	US BANK	Meals	14.56	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
39	3226	US BANK	Meals	14.96	1/31/2018	2009471	CC Recap-Mark W. Lofthus	1/2018-MWL	1/30/2018	ECO
40	3226	US BANK	Meals	240.00	1/31/2018	2009471	CC Recap-Sheryl K. Wutschke	1/2018-SKW	1/30/2018	ACTSAF
41	4042	CRAIG TURNER	Meals	8.00	1/31/2018	356007	EXPENSE REPORT	JAN/2018	2/8/2018	EDU
42	6148	FARMINGTON BAKERY	Meals	32.49	1/31/2018	355755	ROLLS/DONUTS/MUFFINS	2140	1/30/2018	BOD
43	7477	CLASSIC CATERING	Meals	505.28	1/31/2018	355558	BOARD LUNCH	6836	1/23/2018	BOD
44	7696	CHERRY A JORDAN	Meals	77.85	1/31/2018	2900	EXPENSE REPORT	JAN/2018	1/24/2018	BOD
45	2564	SAM'S CLUB	Meals	150.55	2/28/2018	356717	POP.CANDY.STEAM PANS	2/2018-4731	3/15/2018	EFUNC
46	2564	SAM'S CLUB	Meals	156.04	2/28/2018	356717	POP.CANDY.STEAM PANS	2/2018-4731	3/15/2018	EFUNC
47	2625	JANET L LEKSON	Meals	278.53	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
48	3226	US BANK	Meals	55.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	PTRAPP
49	3226	US BANK	Meals	75.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	DEYOE
50	3226	US BANK	Meals	35.01	2/28/2018	2009476	CC Recap-Grant S. Baumberger	2/2018-GSB	3/1/2018	SUBO
51	3226	US BANK	Meals	45.00	2/28/2018	2009476	CC Recap-Grant S. Baumberger	2/2018-GSB	3/1/2018	EDU
52	3226	US BANK	Meals	115.47	2/28/2018	2009476	CC Recap-David J. Benkufsky	2/2018-DJB	3/1/2018	PUR
53	3226	US BANK	Meals	8.74	2/28/2018	2009476	CC Recap-David J. Benkufsky	2/2018-DJB	3/1/2018	EDU
54	3226	US BANK	Meals	15.86	2/28/2018	2009476	CC Recap-David J. Benkufsky	2/2018-DJB	3/1/2018	EDU
55	3226	US BANK	Meals	6.98	2/28/2018	2009476	CC Recap-David J. Benkufsky	2/2018-DJB	3/1/2018	EDU
56	3226	US BANK	Meals	72.16	2/28/2018	2009476	CC Recap-Christene D. Dodge-Ra	2/2018-CDD	3/1/2018	HIRE

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
57	3226	US BANK	Meals	42.14	2/28/2018	2009476	CC Recap-Christene D. Dodge-Ra	2/2018-CDD	3/1/2018	HIRE
58	3226	US BANK	Meals	24.85	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	3/1/2018	BOD
59	3226	US BANK	Meals	68.12	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	3/1/2018	BOD
60	3226	US BANK	Meals	9.98	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	3/1/2018	BOD
61	3226	US BANK	Meals	42.82	2/28/2018	2009476	CC Recap-John E. Ginther	2/2018-JEG	3/1/2018	USO
62	3226	US BANK	Meals	127.21	2/28/2018	2009476	CC Recap-Kimberely A. Helleson	2/2018-KAH	3/1/2018	AFS
63	3226	US BANK	Meals	68.25	2/28/2018	2009476	CC Recap-Kimberely A. Helleson	2/2018-KAH	3/1/2018	AFS
64	3226	US BANK	Meals	15.30	2/28/2018	2009476	CC Recap-Denise D. Hrncir	2/2018-DDH	3/1/2018	WELLNESS
65	3226	US BANK	Meals	125.82	2/28/2018	2009476	CC Recap-Denise D. Hrncir	2/2018-DDH	3/1/2018	WELLNESS
66	3226	US BANK	Meals	4.36	2/28/2018	2009476	CC Recap-Denise D. Hrncir	2/2018-DDH	3/1/2018	WELLNESS
67	3226	US BANK	Meals	23.90	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
68	3226	US BANK	Meals	19.96	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
69	3226	US BANK	Meals	1.34	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
70	3226	US BANK	Meals	24.42	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
71	3226	US BANK	Meals	23.28	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
72	3226	US BANK	Meals	20.30	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
73	3226	US BANK	Meals	47.65	2/28/2018	2009476	CC Recap-Anthony J. Nobach	2/2018-AJN	3/1/2018	DIS
74	3226	US BANK	Meals	16.69	2/28/2018	2009476	CC Recap-Danielle J. Johnson	2/2018-DJJ	3/1/2018	USO
75	3226	US BANK	Meals	469.89	2/28/2018	2009476	CC Recap-Danielle J. Johnson	2/2018-DJJ	3/1/2018	USO
76	3226	US BANK	Meals	194.12	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
77	3226	US BANK	Meals	19.00	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
78	3226	US BANK	Meals	32.13	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
79	3226	US BANK	Meals	43.82	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
80	3226	US BANK	Meals	18.00	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
81	3226	US BANK	Meals	82.76	2/28/2018	2009476	CC Recap-Shannon M. Olson	2/2018-SMO	3/1/2018	CISIMP
82	3226	US BANK	Meals	51.01	2/28/2018	2009476	CC Recap-Brenda K. Kadlec	2/2018-BKK	3/1/2018	FIN
83	3226	US BANK	Meals	63.99	2/28/2018	2009476	CC Recap-Brenda K. Kadlec	2/2018-BKK	3/1/2018	IFS
84	3226	US BANK	Meals	54.00	2/28/2018	2009476	CC Recap-Brenda K. Kadlec	2/2018-BKK	3/1/2018	IFS
85	3226	US BANK	Meals	21.86	2/28/2018	2009476	CC Recap-Randall Poulson	2/2018-RLP	3/1/2018	KEY
86	3226	US BANK	Meals	33.00	2/28/2018	2009476	CC Recap-Richard M. Siebenaler	2/2018-RMS	3/1/2018	EDU
87	3226	US BANK	Meals	28.46	2/28/2018	2009476	CC Recap-Joseph P. Kuhn	2/2018-JPK	3/1/2018	MAI
88	3226	US BANK	Meals	449.45	2/28/2018	2009476	CC Recap-David S. Reinke	2/2018-DSR	3/1/2018	ACS
89	3226	US BANK	Meals	84.99	2/28/2018	2009476	CC Recap-David S. Reinke	2/2018-DSR	3/1/2018	IFS
90	3226	US BANK	Meals	18.77	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
91	3226	US BANK	Meals	10.60	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
92	3226	US BANK	Meals	30.08	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
93	3226	US BANK	Meals	15.08	2/28/2018	2009476	CC Recap-Mark W. Lofthus	2/2018-MWL	3/1/2018	ECO
94	3226	US BANK	Meals	38.86	2/28/2018	2009476	CC Recap-Daniel P. Ross	2/2018-DPR	3/1/2018	VISITS
95	3226	US BANK	Meals	40.32	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
96	3226	US BANK	Meals	59.14	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
97	3226	US BANK	Meals	30.50	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
98	3226	US BANK	Meals	58.60	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
99	3226	US BANK	Meals	79.25	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
100	3226	US BANK	Meals	80.62	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
101	3226	US BANK	Meals	23.00	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
102	3226	US BANK	Meals	22.47	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
103	3226	US BANK	Meals	7.00	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
104	3226	US BANK	Meals	132.75	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
105	3226	US BANK	Meals	117.89	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
106	3226	US BANK	Meals	178.20	2/28/2018	2009476	CC Recap-Sheryl K. Wutschke	2/2018-SKW	3/1/2018	CISIMP
107	3226	US BANK	Meals	11.15	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	EDU
108	3226	US BANK	Meals	10.40	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	EDU
109	3226	US BANK	Meals	10.19	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	EDU
110	3226	US BANK	Meals	49.49	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	VISITS
111	3226	US BANK	Meals	11.24	2/28/2018	2009476	CC Recap-Timothy J. Doherty	2/2018-TJD	3/1/2018	NETTECH
112	3226	US BANK	Meals	15.04	2/28/2018	2009476	CC Recap-Malinda R. Mehrhoff	2/2018-MRM-1109	3/1/2018	HRP

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
113	3226	US BANK	Meals	21.98	2/28/2018	2009476	CC Recap-Malinda R. Mehrhoff	2/2018-MRM-1109	3/1/2018	HRP
114	3226	US BANK	Meals	83.07	2/28/2018	2009476	CC Recap-Greg C. Miller	2/2018-GCM	3/1/2018	AMS
115	3226	US BANK	Meals	28.79	2/28/2018	2009476	CC Recap-Greg C. Miller	2/2018-GCM	3/1/2018	AMS
116	3226	US BANK	Meals	31.00	2/28/2018	2009476	CC Recap-Michael R. Nelson	2/2018-MRN	3/1/2018	HIRE
117	3226	US BANK	Meals	33.42	2/28/2018	2009476	CC Recap-Margaret (Peggy) P. J	2/2018-PPJ	3/1/2018	COMMREL
118	*3226*	*US BANK*	*Meals*	*46.06*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
119	*3226*	*US BANK*	*Meals*	*51.50*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
120	*3226*	*US BANK*	*Meals*	*28.96*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
121	3226	US BANK	Meals	5.74	2/28/2018	2009476	CC Recap-Craig C. Turner	2/2018-CCT	3/1/2018	EDU
122	3226	US BANK	Meals	20.00	2/28/2018	2009476	CC Recap-Craig C. Turner	2/2018-CCT	3/1/2018	EDU
123	3226	US BANK	Meals	20.00	2/28/2018	2009476	CC Recap-Craig C. Turner	2/2018-CCT	3/1/2018	EDU
124	3226	US BANK	Meals	39.60	2/28/2018	2009476	CC Recap-Craig C. Turner	2/2018-CCT	3/1/2018	EDU
125	3226	US BANK	Meals	101.43	2/28/2018	2009476	CC Recap-Bernard M. Kolnberger	2/2018-BMK	3/1/2018	USO
126	4546	ROTARY CLUB OF APPLE VALLEY	Meals	162.50	2/28/2018	356300	G MILLER 1/1-3/31/18	1546	2/22/2018	AMS
127	4573	RICHARD W TEEGARDEN	Meals	77.49	2/28/2018	356583	EXPENSE REPORT	FEB/2018-2	3/8/2018	EDU
128	6148	FARMINGTON BAKERY	Meals	22.03	2/28/2018	356217	ROLLS & MUFFINS	2158	2/20/2018	BOD
129	6148	FARMINGTON BAKERY	Meals	47.29	2/28/2018	356369	ROLLS/MUFFINS	2163	2/27/2018	BOD
130	6421	PIZZA MAN BAR AND GRILL	Meals	81.21	2/28/2018	356230	PIZZA/INVENTORY COUNT	10-007-2/2018	2/20/2018	MAT
131	7477	CLASSIC CATERING	Meals	422.80	2/28/2018	356212	BOARD LUNCH	6904	2/20/2018	BOD
132	7696	CHERRY A JORDAN	Meals	27.84	2/28/2018	2932	EXPENSE REPORT	FEB/2018	2/14/2018	BOD
133	7696	CHERRY A JORDAN	Meals	67.11	2/28/2018	2950	EXPENSE REPORT	FEB/2018.2	2/28/2018	BOD
134	7477	CLASSIC CATERING	Meals	(691.50)	3/15/2018	356692	BOARD LUNCH	7017	3/15/2018	BOD
135	2564	SAM'S CLUB	Meals	134.70	3/31/2018	357253	MEMB-APPLIANCES.SNACKS	3/2018-4731	4/17/2018	WELLNESS
136	3226	US BANK	Meals	20.32	3/31/2018	2009481	CC Recap-Jackie A. Bauer	3/2018-JAB	3/29/2018	IRRIG
137	*3226*	*US BANK*	*Meals*	*41.00*	*3/31/2018*	*2009481*	*CC Recap-Grant S. Baumberger*	*3/2018-GSB*	*3/29/2018*	*AGI2018*
138	3226	US BANK	Meals	51.00	3/31/2018	2009481	CC Recap-Grant S. Baumberger	3/2018-GSB	3/29/2018	EDU
139	3226	US BANK	Meals	14.22	3/31/2018	2009481	CC Recap-David J. Benkufsky	3/2018-DJB	3/29/2018	EDU
140	3226	US BANK	Meals	5.99	3/31/2018	2009481	CC Recap-David J. Benkufsky	3/2018-DJB	3/29/2018	EDU
141	3226	US BANK	Meals	9.49	3/31/2018	2009481	CC Recap-David J. Benkufsky	3/2018-DJB	3/29/2018	EDU
142	3226	US BANK	Meals	65.01	3/31/2018	2009481	CC Recap-Timothy J. Doherty	3/2018-TJD	3/29/2018	KEY
143	3226	US BANK	Meals	6.74	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
144	3226	US BANK	Meals	35.96	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
145	3226	US BANK	Meals	27.99	3/31/2018	2009481	CC Recap-Michael G. Fosse	3/2018-MGF	3/29/2018	ACS
146	3226	US BANK	Meals	180.00	3/31/2018	2009481	CC Recap-Kevin S. Fowler	3/2018-KSF	3/29/2018	SAF
147	3226	US BANK	Meals	150.79	3/31/2018	2009481	CC Recap-Kimberely A. Helleson	3/2018-KAH	3/29/2018	CUS
148	3226	US BANK	Meals	113.02	3/31/2018	2009481	CC Recap-Denise D. Hrncir	3/2018-DDH	3/29/2018	WELLNESS
149	3226	US BANK	Meals	56.32	3/31/2018	2009481	CC Recap-Glenda Hewitt	3/2018-GLH	3/29/2018	AEN
150	3226	US BANK	Meals	56.00	3/31/2018	2009481	CC Recap-Glenda Hewitt	3/2018-GLH	3/29/2018	AEN
151	3226	US BANK	Meals	10.48	3/31/2018	2009481	CC Recap-Brenda K. Kadlec	3/2018-BKK	3/29/2018	CIGROUP
152	3226	US BANK	Meals	2.68	3/31/2018	2009481	CC Recap-Brenda K. Kadlec	3/2018-BKK	3/29/2018	CIGROUP
153	3226	US BANK	Meals	339.66	3/31/2018	2009481	CC Recap-Brenda K. Kadlec	3/2018-BKK	3/29/2018	CIGROUP
154	3226	US BANK	Meals	100.88	3/31/2018	2009481	CC Recap-Bernard M. Kolnberger	3/2018-BMK	3/29/2018	TRA
155	3226	US BANK	Meals	75.03	3/31/2018	2009481	CC Recap-Paul G. Kehrer	3/2018-PGK	3/29/2018	MAI
156	3226	US BANK	Meals	8.50	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO
157	3226	US BANK	Meals	36.84	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO
158	3226	US BANK	Meals	8.59	3/31/2018	2009481	CC Recap-Mark W. Lofthus	3/2018-MWL	3/29/2018	ECO
159	3226	US BANK	Meals	30.00	3/31/2018	2009481	CC Recap-Malinda R. Mehrhoff	3/2018-MRM-6676	3/29/2018	HRP
160	3226	US BANK	Meals	61.99	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	DIS
161	3226	US BANK	Meals	60.92	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	DIS
162	3226	US BANK	Meals	25.60	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	EDU
163	3226	US BANK	Meals	42.44	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	EDU
164	3226	US BANK	Meals	29.28	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	EDU
165	3226	US BANK	Meals	294.36	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	BODELECT
166	3226	US BANK	Meals	14.04	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	BOD
167	3226	US BANK	Meals	16.16	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	BOD
168	3226	US BANK	Meals	36.92	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	DIS

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
169	3226	US BANK	Meals	29.94	3/31/2018	2009481	CC Recap-Anthony J. Nobach	3/2018-AJN	3/29/2018	DIS
170	3226	US BANK	Meals	76.07	3/31/2018	2009481	CC Recap-Shannon M. Olson	3/2018-SMO	3/29/2018	CISIMP
171	3226	US BANK	Meals	11.03	3/31/2018	2009481	CC Recap-Stephanie M. Pederson	3/2018-SMP	3/29/2018	DSM
172	3226	US BANK	Meals	68.64	3/31/2018	2009481	CC Recap-Stephanie M. Pederson	3/2018-SMP	3/29/2018	DSM
173	3226	US BANK	Meals	29.71	3/31/2018	2009481	CC Recap-Davin H. Peterson	3/2018-DHP	3/29/2018	ETS
174	3226	US BANK	Meals	120.75	3/31/2018	2009481	CC Recap-Malinda R. Mehrhoff	3/2018-MRM-1109	3/29/2018	EDU
175	3226	US BANK	Meals	40.74	3/31/2018	2009481	CC Recap-Greg C. Miller	3/2018-GCM	3/29/2018	AMS
176	3226	US BANK	Meals	37.60	3/31/2018	2009481	CC Recap-Greg C. Miller	3/2018-GCM	3/29/2018	AMS
177	3226	US BANK	Meals	80.89	3/31/2018	2009481	CC Recap-Greg C. Miller	3/2018-GCM	3/29/2018	AMS
178	3226	US BANK	Meals	78.26	3/31/2018	2009481	CC Recap-Greg C. Miller	3/2018-GCM	3/29/2018	AMS
179	3226	US BANK	Meals	65.00	3/31/2018	2009481	CC Recap-Michael R. Nelson	3/2018-MRN	3/29/2018	IFS
180	3226	US BANK	Meals	138.83	3/31/2018	2009481	CC Recap-Daniel P. Ross	3/2018-DPR	3/29/2018	CIGROUP
181	3226	US BANK	Meals	31.62	3/31/2018	2009481	CC Recap-Thomas E. Schmitz	3/2018-TES	3/29/2018	EDU
182	3226	US BANK	Meals	23.11	3/31/2018	2009481	CC Recap-Thomas E. Schmitz	3/2018-TES	3/29/2018	EDU
183	3226	US BANK	Meals	25.42	3/31/2018	2009481	CC Recap-Jeffrey L. Schoenecke	3/2018-JLS	3/29/2018	ETS
184	3226	US BANK	Meals	18.08	3/31/2018	2009481	CC Recap-Jeffrey D Schultz	3/2018-JDS	3/29/2018	EDU
185	3226	US BANK	Meals	35.14	3/31/2018	2009481	CC Recap-Jane E. Siebenaler	3/2018-JES	3/29/2018	VISITS
186	3226	US BANK	Meals	30.95	3/31/2018	2009481	CC Recap-Julie A. Simonsen	3/2018-JAS	3/29/2018	YOUTH
187	3226	US BANK	Meals	118.01	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	METRD
188	3226	US BANK	Meals	208.57	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
189	3226	US BANK	Meals	124.41	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
190	3226	US BANK	Meals	156.96	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
191	3226	US BANK	Meals	10.70	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
192	3226	US BANK	Meals	22.39	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
193	3226	US BANK	Meals	124.02	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
194	3226	US BANK	Meals	107.98	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
195	3226	US BANK	Meals	119.51	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
196	3226	US BANK	Meals	184.22	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
197	3226	US BANK	Meals	240.73	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
198	3226	US BANK	Meals	281.20	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
199	3226	US BANK	Meals	26.91	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
200	3226	US BANK	Meals	59.79	3/31/2018	2009481	CC Recap-Sheryl K. Wutschke	3/2018-SKW	3/29/2018	CISIMP
201	3226	US BANK	Meals	32.97	3/31/2018	2009481	CC Recap-Craig C. Turner	3/2018-CCT	3/29/2018	EDU
202	3226	US BANK	Meals	53.89	3/31/2018	2009481	CC Recap-Gregory D. Weber	3/2018-GDW	3/29/2018	EDU
203	4573	RICHARD W TEEGARDEN	Meals	112.67	3/31/2018	356583	EXPENSE REPORT	MAR/2018	3/8/2018	EDU
204	5426	PAUL A TRAPP	Meals	131.33	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
205	6148	FARMINGTON BAKERY	Meals	30.00	3/31/2018	356701	2 DZ ROLLS	2177	3/15/2018	CISIMP
206	6148	FARMINGTON BAKERY	Meals	122.00	3/31/2018	356844	ROLLS/CROP DAY	2183	3/22/2018	IRRIG
207	6148	FARMINGTON BAKERY	Meals	31.04	3/31/2018	356938	ROLLS/MUFFINS/DONUTS	2191	3/29/2018	BOD
208	7174	TROPHY HOUSE	Meals	702.43	3/31/2018	356875	CROP DAY LUNCH	MAR-14-18	3/22/2018	IRRIG
209	7174	TROPHY HOUSE	Meals	11.86	3/31/2018	356875	CROP DAY LUNCH	MAR-14-18	3/22/2018	IRRIG
210	7174	TROPHY HOUSE	Meals	0.43	3/31/2018	356875	CROP DAY LUNCH	MAR-14-18	3/22/2018	IRRIG
211	7477	CLASSIC CATERING	Meals	691.50	3/31/2018	356692	BOARD LUNCH	7017	3/15/2018	BOD
212	7477	CLASSIC CATERING	Meals	792.74	3/31/2018	356692	BOARD LUNCH	7017	3/15/2018	BOD
213	7696	CHERRY A JORDAN	Meals	72.40	3/31/2018	2989	EXPENSE REPORT	MAR/2018	3/28/2018	BOD
214	8207	JOHN D DEYOE	Meals	7.72	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
215	8568	JAMES R STENSTROM	Meals	35.00	3/31/2018	357075	EXPENSE REPORT	FEB/2018	4/5/2018	IFS
216	8650	STEPHANIE M PEDERSON	Meals	13.25	3/31/2018	356957	EXPENSE REPORT	MAR/2018	3/29/2018	ELECCAR
217	2625	JANET L LEKSON	Meals	309.59	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
218	2933	MARGARET P JOHNSON	Meals	60.40	4/30/2018	3045	EXPENSE REPORT	APR/2018	5/9/2018	COMMREL
219	3226	US BANK	Meals	55.96	4/30/2018	2009486	CC Recap-Michael G. Fosse	4/2018-MGF	4/30/2018	WEBSITE
220	3226	US BANK	Meals	28.98	4/30/2018	2009486	CC Recap-Kimberely A. Helleson	4/2018-KAH	4/30/2018	CUS
221	3226	US BANK	Meals	15.80	4/30/2018	2009486	CC Recap-Denise D. Hrncir	4/2018-DDH	4/30/2018	WELLNESS
222	3226	US BANK	Meals	30.84	4/30/2018	2009486	CC Recap-Denise D. Hrncir	4/2018-DDH	4/30/2018	HRP
223	3226	US BANK	Meals	79.49	4/30/2018	2009486	CC Recap-Danielle J. Johnson	4/2018-DJJ	4/30/2018	ETS
224	3226	US BANK	Meals	21.17	4/30/2018	2009486	CC Recap-Danielle J. Johnson	4/2018-DJJ	4/30/2018	ETS

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
225	3226	US BANK	Meals	230.51	4/30/2018	2009486	CC Recap-Danielle J. Johnson	4/2018-DJJ	4/30/2018	ETS
226	3226	US BANK	Meals	117.35	4/30/2018	2009486	CC Recap-Danielle J. Johnson	4/2018-DJJ	4/30/2018	ETS
227	3226	US BANK	Meals	10.44	4/30/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	BOD
228	3226	US BANK	Meals	18.96	4/30/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	BOD
229	3226	US BANK	Meals	15.95	4/30/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	BOD
230	3226	US BANK	Meals	26.00	4/30/2018	2009486	CC Recap-Bernard M. Kolnberger	4/2018-BMK	4/30/2018	USO
231	3226	US BANK	Meals	100.00	4/30/2018	2009486	CC Recap-Bernard M. Kolnberger	4/2018-BMK	4/30/2018	USO
232	3226	US BANK	Meals	100.00	4/30/2018	2009486	CC Recap-Bernard M. Kolnberger	4/2018-BMK	4/30/2018	USO
233	3226	US BANK	Meals	75.00	4/30/2018	2009486	CC Recap-Bernard M. Kolnberger	4/2018-BMK	4/30/2018	USO
234	3226	US BANK	Meals	56.24	4/30/2018	2009486	CC Recap-Joseph P. Kuhn	4/2018-JPK	4/30/2018	MAI
235	3226	US BANK	Meals	71.56	4/30/2018	2009486	CC Recap-Douglas R. Larson	4/2018-DRL	4/30/2018	LEGIS
236	3226	US BANK	Meals	31.95	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
237	3226	US BANK	Meals	73.44	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
238	3226	US BANK	Meals	9.24	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
239	3226	US BANK	Meals	35.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
240	3226	US BANK	Meals	30.00	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
241	3226	US BANK	Meals	9.20	4/30/2018	2009486	CC Recap-Mark W. Lofthus	4/2018-MWL	4/30/2018	ECO
242	3226	US BANK	Meals	108.36	4/30/2018	2009486	CC Recap-Ann J. Maniaci	4/2018-AJM	4/30/2018	AFS
243	3226	US BANK	Meals	3.98	4/30/2018	2009486	CC Recap-Malinda R. Mehrhoff	4/2018-MRM-1109	4/30/2018	WELLNESS
244	3226	US BANK	Meals	47.76	4/30/2018	2009486	CC Recap-Greg C. Miller	4/2018-GCM	4/30/2018	AMS
245	3226	US BANK	Meals	8.30	4/30/2018	2009486	CC Recap-Joseph A. Miller	4/2018-JAM	4/30/2018	BRANDING
246	3226	US BANK	Meals	14.17	4/30/2018	2009486	CC Recap-Anthony J. Nobach	4/2018-AJN	4/30/2018	DIS
247	3226	US BANK	Meals	40.66	4/30/2018	2009486	CC Recap-Anthony J. Nobach	4/2018-AJN	4/30/2018	DIS
248	3226	US BANK	Meals	25.98	4/30/2018	2009486	CC Recap-Anthony J. Nobach	4/2018-AJN	4/30/2018	DIS
249	3226	US BANK	Meals	29.94	4/30/2018	2009486	CC Recap-Anthony J. Nobach	4/2018-AJN	4/30/2018	DIS
250	3226	US BANK	Meals	29.71	4/30/2018	2009486	CC Recap-Shannon M. Olson	4/2018-SMO	4/30/2018	CISIMP
251	3226	US BANK	Meals	14.75	4/30/2018	2009486	CC Recap-Michael D. Plutowski	4/2018-MDP	4/30/2018	DSM
252	3226	US BANK	Meals	56.24	4/30/2018	2009486	CC Recap-David S. Reinke	4/2018-DSR	4/30/2018	DSM
253	3226	US BANK	Meals	65.62	4/30/2018	2009486	CC Recap-Daniel P. Ross	4/2018-DPR	4/30/2018	VISITS
254	3226	US BANK	Meals	39.12	4/30/2018	2009486	CC Recap-Thomas E. Schmitz	4/2018-TES	4/30/2018	NCD
255	3226	US BANK	Meals	120.35	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	CISIMP
256	3226	US BANK	Meals	232.29	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	CISIMP
257	3226	US BANK	Meals	66.21	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	CISIMP
258	3226	US BANK	Meals	165.75	4/30/2018	2009486	CC Recap-Sheryl K. Wutschke	4/2018-SKW	4/30/2018	MET
259	3226	US BANK	Meals	26.17	4/30/2018	2009486	CC Recap-Gregory D. Weber	4/2018-GDW	4/30/2018	EDU
260	3226	US BANK	Meals	35.98	4/30/2018	2009486	CC Recap-Betty Jo A. Kiesow	4/2018-BAK	4/30/2018	NCD
261	6148	FARMINGTON BAKERY	Meals	31.24	4/30/2018	357634	ROLLS/MUFFINS/DONUTS	2223	5/1/2018	BOD
262	7477	CLASSIC CATERING	Meals	502.60	4/30/2018	357340	4/26 BOARD LUNCH	7135	4/24/2018	BOD
263	8207	JOHN D DEYOE	Meals	155.83	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
264	7477	CLASSIC CATERING	Meals	525.90	5/30/2018	358387	5/31/18 BOARD/DIR LUNCH	7199	5/29/2018	BOD
265	538	CITY OF EAGAN	Meals	285.00	5/31/2018	357992	ECC FOOD/BEV AV PKG	9546	5/15/2018	SOLAR
266	2564	SAM'S CLUB	Meals	150.72	5/31/2018	358800	5/1-5/30/18	5/2018-4731	6/19/2018	BENE
267	2564	SAM'S CLUB	Meals	3.55	5/31/2018	358800	5/1-5/30/18	5/2018-4731	6/19/2018	COMMREL
268	3048	MARGARET D SCHREINER	Meals	119.20	5/31/2018	3077	EXPENSE REPORT	MAY/2018	6/8/2018	SCHREINER
269	3226	US BANK	Meals	38.63	5/31/2018	2009490	CC Recap-Michael G. Fosse	5/2018-MGF	5/31/2018	CUS
270	3226	US BANK	Meals	48.92	5/31/2018	2009490	CC Recap-Glenda Hewitt	5/2018-GLH	5/31/2018	AEN
271	3226	US BANK	Meals	136.13	5/31/2018	2009490	CC Recap-Denise D. Hrncir	5/2018-DDH	5/31/2018	WELLNESS
272	3226	US BANK	Meals	14.33	5/31/2018	2009490	CC Recap-Denise D. Hrncir	5/2018-DDH	5/31/2018	WELLNESS
273	3226	US BANK	Meals	53.18	5/31/2018	2009490	CC Recap-Danielle J. Johnson	5/2018-DJJ	5/31/2018	TRA
274	3226	US BANK	Meals	136.62	5/31/2018	2009490	CC Recap-Danielle J. Johnson	5/2018-DJJ	5/31/2018	USO
275	3226	US BANK	Meals	21.13	5/31/2018	2009490	CC Recap-Danielle J. Johnson	5/2018-DJJ	5/31/2018	USO
276	3226	US BANK	Meals	13.06	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	BOD
277	3226	US BANK	Meals	19.96	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	BOD
278	3226	US BANK	Meals	67.11	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	BOD
279	3226	US BANK	Meals	(2.98)	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	BOD
280	3226	US BANK	Meals	16.03	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	BOD

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
281	3226	US BANK	Meals	13.98	5/31/2018	2009490	CC Recap-Brenda K. Kadlec	5/2018-BKK	5/31/2018	ACS
282	3226	US BANK	Meals	71.07	5/31/2018	2009490	CC Recap-Brenda K. Kadlec	5/2018-BKK	5/31/2018	SOLAR
283	3226	US BANK	Meals	142.35	5/31/2018	2009490	CC Recap-Brenda K. Kadlec	5/2018-BKK	5/31/2018	ACS
284	3226	US BANK	Meals	16.99	5/31/2018	2009490	CC Recap-Jessica R. Klein	5/2018-JRK	5/31/2018	EDU
285	3226	US BANK	Meals	23.90	5/31/2018	2009490	CC Recap-Craig Knudsen	5/2018-CEK	5/31/2018	ROW
286	3226	US BANK	Meals	55.10	5/31/2018	2009490	CC Recap-Douglas R. Larson	5/2018-DRL	5/31/2018	REG
287	3226	US BANK	Meals	48.99	5/31/2018	2009490	CC Recap-Douglas R. Larson	5/2018-DRL	5/31/2018	REG
288	3226	US BANK	Meals	13.95	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
289	3226	US BANK	Meals	49.94	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
290	3226	US BANK	Meals	31.96	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
291	3226	US BANK	Meals	21.72	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
292	3226	US BANK	Meals	6.99	5/31/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	5/31/2018	ECO
293	3226	US BANK	Meals	356.11	5/31/2018	2009490	CC Recap-Malinda R. Mehrhoff	5/2018-MRM-1109	5/31/2018	EDU
294	3226	US BANK	Meals	286.89	5/31/2018	2009490	CC Recap-Malinda R. Mehrhoff	5/2018-MRM-1109	5/31/2018	EDU
295	3226	US BANK	Meals	11.00	5/31/2018	2009490	CC Recap-Michael D. Plutowski	5/2018-MDP	5/31/2018	DSM
296	3226	US BANK	Meals	98.09	5/31/2018	2009490	CC Recap-David S. Reinke	5/2018-DSR	5/31/2018	DSM
297	3226	US BANK	Meals	48.09	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	ECO
298	3226	US BANK	Meals	26.43	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	ANMTG
299	3226	US BANK	Meals	2.59	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	ANMTG
300	3226	US BANK	Meals	24.46	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	ANMTG
301	3226	US BANK	Meals	525.16	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	ANMTG
302	3226	US BANK	Meals	14.84	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
303	3226	US BANK	Meals	26.57	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
304	3226	US BANK	Meals	20.09	5/31/2018	2009490	CC Recap-Tanya S. Wolfs	5/2018-TSW	5/31/2018	EDU
305	3226	US BANK	Meals	119.96	5/31/2018	2009490	CC Recap-Sheryl K. Wutschke	5/2018-SKW	5/31/2018	METRD
306	3226	US BANK	Meals	43.71	5/31/2018	2009490	CC Recap-Sheryl K. Wutschke	5/2018-SKW	5/31/2018	METRD
307	3226	US BANK	Meals	35.35	5/31/2018	2009490	CC Recap-Margaret (Peggy) P Jo	5/2018-PPJ	5/31/2018	COMMREL
308	3226	US BANK	Meals	14.12	5/31/2018	2009490	CC Recap-Margaret (Peggy) P Jo	5/2018-PPJ	5/31/2018	COMMREL
309	3226	US BANK	Meals	71.42	5/31/2018	2009490	CC Recap-Greg C. Miller	5/2018-GCM	5/31/2018	AMS
310	3226	US BANK	Meals	86.77	5/31/2018	2009490	CC Recap-Greg C. Miller	5/2018-GCM	5/31/2018	AMS
311	3226	US BANK	Meals	61.88	5/31/2018	2009490	CC Recap-Greg C. Miller	5/2018-GCM	5/31/2018	AMS
312	3226	US BANK	Meals	56.71	5/31/2018	2009490	CC Recap-Greg C. Miller	5/2018-GCM	5/31/2018	AMS
313	3226	US BANK	Meals	18.84	5/31/2018	2009490	CC Recap-Joseph A. Miller	5/2018-JAM	5/31/2018	ANMTG
314	3226	US BANK	Meals	103.08	5/31/2018	2009490	CC Recap-Joseph A. Miller	5/2018-JAM	5/31/2018	BRANDING
315	3226	US BANK	Meals	977.87	5/31/2018	2009490	CC Recap-Joseph A. Miller	5/2018-JAM	5/31/2018	BRANDING
316	3226	US BANK	Meals	9.25	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
317	3226	US BANK	Meals	125.73	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
318	3226	US BANK	Meals	16.50	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
319	3226	US BANK	Meals	29.94	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
320	3226	US BANK	Meals	22.02	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
321	3226	US BANK	Meals	14.97	5/31/2018	2009490	CC Recap-Anthony J. Nobach	5/2018-AJN	5/31/2018	DIS
322	3226	US BANK	Meals	64.45	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
323	3226	US BANK	Meals	13.18	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
324	3226	US BANK	Meals	37.85	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
325	3226	US BANK	Meals	61.27	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
326	3226	US BANK	Meals	72.76	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
327	3226	US BANK	Meals	13.80	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
328	3226	US BANK	Meals	41.83	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
329	3226	US BANK	Meals	38.67	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	EDU
330	3226	US BANK	Meals	101.91	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	KEY
331	3226	US BANK	Meals	80.03	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	VISITS
332	3226	US BANK	Meals	31.78	5/31/2018	2009490	CC Recap-Jane E. Siebenaler	5/2018-JES	5/31/2018	ELECCAR
333	3226	US BANK	Meals	34.38	5/31/2018	2009490	CC Recap-McKennon M. VanderVee	5/2018-MMV	5/31/2018	SUBO
334	3226	US BANK	Meals	4.05	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
335	3226	US BANK	Meals	12.09	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
336	3226	US BANK	Meals	16.03	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
337	3226	US BANK	Meals	15.12	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
338	3226	US BANK	Meals	12.96	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
339	3226	US BANK	Meals	7.27	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
340	3226	US BANK	Meals	7.53	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	EDU
341	3226	US BANK	Meals	74.45	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	ETS
342	3226	US BANK	Meals	25.43	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	5/2018-JLS	5/31/2018	ETS
343	3226	US BANK	Meals	13.69	5/31/2018	2009490	CC Recap-Craig C. Turner	5/2018-CCT	5/31/2018	REGENGINEER
344	3226	US BANK	Meals	66.00	5/31/2018	2009490	CC Recap-Kevin S. Fowler	5/2018-KSF	5/31/2018	SAF
345	3226	US BANK	Meals	711.33	5/31/2018	2009490	CC Recap-Jackie A. Bauer	5/2018-JAB	5/31/2018	E3TRAIN
346	4919	CLAY VAN DE BOGART	Meals	74.47	5/31/2018	358598	EXPENSE REPORT	MAY/2018	6/7/2018	VAN
347	2564	SAM'S CLUB	Meals	160.51	6/30/2018	359637	6/14/18-6/22/18	6/2018-4731	7/17/2018	AEN
348	3226	US BANK	Meals	29.05	6/30/2018	2009496	CC Recap-Michael G. Fosse	6/2018-MGF	7/2/2018	ACS
349	3226	US BANK	Meals	16.71	6/30/2018	2009496	CC Recap-Glenda Hewitt	6/2018-GLH	7/2/2018	AEN
350	3226	US BANK	Meals	112.26	6/30/2018	2009496	CC Recap-Sheryl K. Wutschke	6/2018-SKW	7/2/2018	CISIMP
351	3226	US BANK	Meals	41.02	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-1109	7/2/2018	EDU
352	3226	US BANK	Meals	44.47	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-1109	7/2/2018	WELLNESS
353	3226	US BANK	Meals	17.82	6/30/2018	2009496	CC Recap-Malinda R. Mehrhoff	6/2018-MRM-1109	7/2/2018	WELLNESS
354	3226	US BANK	Meals	163.68	6/30/2018	2009496	CC Recap-Denise D. Hrncir	6/2018-DDH	7/2/2018	WELLNESS
355	3226	US BANK	Meals	6.91	6/30/2018	2009496	CC Recap-Denise D. Hrncir	6/2018-DDH	7/2/2018	WELLNESS
356	3226	US BANK	Meals	16.15	6/30/2018	2009496	CC Recap-Denise D. Hrncir	6/2018-DDH	7/2/2018	WELLNESS
357	3226	US BANK	Meals	8.97	6/30/2018	2009496	CC Recap-Denise D. Hrncir	6/2018-DDH	7/2/2018	WELLNESS
358	3226	US BANK	Meals	78.42	6/30/2018	2009496	CC Recap-Douglas R. Larson	6/2018-DRL	7/2/2018	SOLAR
359	3226	US BANK	Meals	55.39	6/30/2018	2009496	CC Recap-Douglas R. Larson	6/2018-DRL	7/2/2018	REG
360	3226	US BANK	Meals	33.40	6/30/2018	2009496	CC Recap-Douglas R. Larson	6/2018-DRL	7/2/2018	POWSUP
361	3226	US BANK	Meals	142.81	6/30/2018	2009496	CC Recap-Kimberely A. Helleson	6/2018-KAH	7/2/2018	CUS
362	3226	US BANK	Meals	12.64	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
363	3226	US BANK	Meals	5.80	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
364	3226	US BANK	Meals	15.39	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
365	3226	US BANK	Meals	9.20	6/30/2018	2009496	CC Recap-Mark W. Lofthus	6/2018-MWL	7/2/2018	ECO
366	3226	US BANK	Meals	200.00	6/30/2018	2009496	CC Recap-David S. Reinke	6/2018-DSR	7/2/2018	CUS
367	3226	US BANK	Meals	17.14	6/30/2018	2009496	CC Recap-David S. Reinke	6/2018-DSR	7/2/2018	ELECCAR
368	3226	US BANK	Meals	121.19	6/30/2018	2009496	CC Recap-David S. Reinke	6/2018-DSR	7/2/2018	ELECCAR
369	3226	US BANK	Meals	24.00	6/30/2018	2009496	CC Recap-Grant S. Baumberger	6/2018-GSB	7/2/2018	EDU
370	3226	US BANK	Meals	90.30	6/30/2018	2009496	CC Recap-Grant S. Baumberger	6/2018-GSB	7/2/2018	EDU
371	3226	US BANK	Meals	15.00	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
372	3226	US BANK	Meals	58.75	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
373	3226	US BANK	Meals	34.71	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
374	3226	US BANK	Meals	13.19	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
375	3226	US BANK	Meals	29.35	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
376	3226	US BANK	Meals	7.70	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
377	3226	US BANK	Meals	18.19	6/30/2018	2009496	CC Recap-Kevin S. Fowler	6/2018-KSF	7/2/2018	SAF
378	3226	US BANK	Meals	20.94	6/30/2018	2009496	CC Recap-Margaret (Peggy) P Jo	6/2018-PPJ	7/2/2018	COMMREL
379	3226	US BANK	Meals	17.77	6/30/2018	2009496	CC Recap-Cherry A. Jordan	6/2018-CAJ	7/2/2018	BOD
380	3226	US BANK	Meals	110.65	6/30/2018	2009496	CC Recap-Cherry A. Jordan	6/2018-CAJ	7/2/2018	BOD
381	3226	US BANK	Meals	640.85	6/30/2018	2009496	CC Recap-Danielle J. Johnson	6/2018-DJJ	7/2/2018	AUO
382	3226	US BANK	Meals	29.00	6/30/2018	2009496	CC Recap-Bernard M. Kolnberger	6/2018-BMK	7/2/2018	USO
383	3226	US BANK	Meals	64.47	6/30/2018	2009496	CC Recap-Joseph P. Kuhn	6/2018-JPK	7/2/2018	MAI
384	3226	US BANK	Meals	23.28	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
385	3226	US BANK	Meals	39.08	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
386	3226	US BANK	Meals	83.07	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
387	3226	US BANK	Meals	446.41	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
388	3226	US BANK	Meals	59.12	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
389	3226	US BANK	Meals	43.35	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
390	3226	US BANK	Meals	39.01	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
391	3226	US BANK	Meals	55.26	6/30/2018	2009496	CC Recap-Greg C. Miller	6/2018-GCM	7/2/2018	AMS
392	3226	US BANK	Meals	61.75	6/30/2018	2009496	CC Recap-Joseph A. Miller	6/2018-JAM	7/2/2018	MKT

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
393	*3226*	*US BANK*	*Meals*	*14.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
394	*3226*	*US BANK*	*Meals*	*21.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
395	*3226*	*US BANK*	*Meals*	*23.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
396	*3226*	*US BANK*	*Meals*	*15.00*	*6/30/2018*	*2009496*	*CC Recap-Gregory D. Weber*	*6/2018-GDW*	*7/2/2018*	*AGI2018*
397	3226	US BANK	Meals	135.72	6/30/2018	2009496	CC Recap-Anthony J. Nobach	6/2018-AJN	7/2/2018	DIS
398	3226	US BANK	Meals	29.94	6/30/2018	2009496	CC Recap-Anthony J. Nobach	6/2018-AJN	7/2/2018	DIS
399	3226	US BANK	Meals	33.83	6/30/2018	2009496	CC Recap-Shannon M. Olson	6/2018-SMO	7/2/2018	BILL
400	5426	PAUL A TRAPP	Meals	37.89	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
401	6148	FARMINGTON BAKERY	Meals	31.04	6/30/2018	359158	ROLLS/MUFFINS/DONUTS	990876	7/3/2018	BOD
402	7477	CLASSIC CATERING	Meals	481.71	6/30/2018	358821	BOARD LUNCHEON	7335	6/21/2018	BOD
403	337	MN RURAL ELECTRIC ASSOCIATION	Meals	1,326.98	7/31/2018	360874	2018 YOUTH TOUR EXP	INV00013571	8/28/2018	YOUTH
404	2564	SAM'S CLUB	Meals	170.32	7/31/2018	360527	MBRSHIP/BEVERAGES/FRUIT	7/2018-4731	8/16/2018	WELLNESS
405	2564	SAM'S CLUB	Meals	34.19	7/31/2018	360527	MBRSHIP/BEVERAGES/FRUIT	7/2018-4731	8/16/2018	AEN
406	2564	SAM'S CLUB	Meals	245.23	7/31/2018	360527	MBRSHIP/BEVERAGES/FRUIT	7/2018-4731	8/16/2018	AUO
407	3226	US BANK	Meals	36.88	7/31/2018	2009501	CC Recap-Christene D. Dodge-Ra	7/2018-CDD	7/31/2018	HIRE
408	3226	US BANK	Meals	33.46	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
409	3226	US BANK	Meals	23.17	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	ACS
410	3226	US BANK	Meals	34.68	7/31/2018	2009501	CC Recap-Michael G. Fosse	7/2018-MGF	7/31/2018	CIRC2018
411	3226	US BANK	Meals	35.70	7/31/2018	2009501	CC Recap-Kevin S. Fowler	7/2018-KSF	7/31/2018	SAF
412	3226	US BANK	Meals	11.00	7/31/2018	2009501	CC Recap-Kimberely A. Helleson	7/2018-KAH	7/31/2018	CUS
413	3226	US BANK	Meals	58.80	7/31/2018	2009501	CC Recap-Glenda Hewitt	7/2018-GLH	7/31/2018	AEN
414	3226	US BANK	Meals	88.54	7/31/2018	2009501	CC Recap-Denise D. Hrncir	7/2018-DDH	7/31/2018	WELLNESS
415	3226	US BANK	Meals	44.76	7/31/2018	2009501	CC Recap-Denise D. Hrncir	7/2018-DDH	7/31/2018	WELLNESS
416	3226	US BANK	Meals	16.96	7/31/2018	2009501	CC Recap-Denise D. Hrncir	7/2018-DDH	7/31/2018	WELLNESS
417	3226	US BANK	Meals	14.33	7/31/2018	2009501	CC Recap-Denise D. Hrncir	7/2018-DDH	7/31/2018	WELLNESS
418	3226	US BANK	Meals	3.99	7/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	BOD
419	3226	US BANK	Meals	15.87	7/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	BOD
420	3226	US BANK	Meals	20.67	7/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	BOD
421	3226	US BANK	Meals	103.24	7/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	BOD
422	3226	US BANK	Meals	29.23	7/31/2018	2009501	CC Recap-Douglas R. Larson	7/2018-DRL	7/31/2018	POWSUP
423	3226	US BANK	Meals	53.85	7/31/2018	2009501	CC Recap-Mark W. Lofthus	7/2018-MWL	7/31/2018	ECO
424	3226	US BANK	Meals	30.51	7/31/2018	2009501	CC Recap-Malinda R. Mehrhoff	7/2018-MRM-6676	7/31/2018	HRP
425	3226	US BANK	Meals	23.98	7/31/2018	2009501	CC Recap-Malinda R. Mehrhoff	7/2018-MRM-6676	7/31/2018	EDU
426	3226	US BANK	Meals	41.23	7/31/2018	2009501	CC Recap-Greg C. Miller	7/2018-GCM	7/31/2018	AMS
427	3226	US BANK	Meals	55.59	7/31/2018	2009501	CC Recap-Greg C. Miller	7/2018-GCM	7/31/2018	AMS
428	3226	US BANK	Meals	45.15	7/31/2018	2009501	CC Recap-Anthony J Nobach	7/2018-AJN	7/31/2018	DIS
429	3226	US BANK	Meals	62.12	7/31/2018	2009501	CC Recap-Stephanie M. Pederson	7/2018-SMP	7/31/2018	E3TRAIN
430	3226	US BANK	Meals	34.74	7/31/2018	2009501	CC Recap-David S. Reinke	7/2018-DSR	7/31/2018	CIPGOALS
431	3226	US BANK	Meals	60.27	7/31/2018	2009501	CC Recap-David S. Reinke	7/2018-DSR	7/31/2018	DSM
432	3226	US BANK	Meals	58.05	7/31/2018	2009501	CC Recap-Andrew F. Schrupp	7/2018-AFS	7/31/2018	USO
433	3226	US BANK	Meals	29.94	7/31/2018	2009501	CC Recap-John A. Thurmes	7/2018-JAT	7/31/2018	DIS
434	3226	US BANK	Meals	63.51	7/31/2018	2009501	CC Recap-Lou Ann D. Weflen	7/2018-LAW	7/31/2018	AFS
435	3226	US BANK	Meals	19.94	7/31/2018	2009501	CC Recap-Joseph A. Miller	7/2018-JAM	7/31/2018	BRANDING
436	3226	US BANK	Meals	117.75	7/31/2018	2009501	CC Recap-Danielle J. Johnson	7/2018-DJJ	7/31/2018	ETS
437	3226	US BANK	Meals	179.13	7/31/2018	2009501	CC Recap-Danielle J. Johnson	7/2018-DJJ	7/31/2018	ETS
438	3226	US BANK	Meals	66.33	7/31/2018	2009501	CC Recap-Bernard M. Kolnberger	7/2018-BMK	7/31/2018	USO
439	3226	US BANK	Meals	23.21	7/31/2018	2009501	CC Recap-Bernard M. Kolnberger	7/2018-BMK	7/31/2018	USO
440	3226	US BANK	Meals	203.33	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
441	3226	US BANK	Meals	12.79	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
442	3226	US BANK	Meals	104.89	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
443	3226	US BANK	Meals	43.67	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
444	3226	US BANK	Meals	51.01	7/31/2018	2009501	CC Recap-Sheryl K. Wutschke	7/2018-SKW	7/31/2018	CISIMP
445	3226	US BANK	Meals	47.54	7/31/2018	2009501	CC Recap-Betty Jo A. Kiesow	7/2018-BAK	7/31/2018	NCD
446	3226	US BANK	Meals	28.00	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	7/2018-JLS	7/31/2018	AUO
447	3226	US BANK	Meals	38.11	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	7/2018-JLS	7/31/2018	AUO
448	*3226*	*US BANK*	*Meals*	*22.45*	*7/31/2018*	*2009501*	*CC Recap-Craig C. Turner*	*7/2018-CCT*	*7/31/2018*	*AGI2018*

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
449	6148	FARMINGTON BAKERY	Meals	29.49	7/31/2018	359606	ROLLS/MUFFINS/DANISH	990893	7/17/2018	METRD
450	7477	CLASSIC CATERING	Meals	465.65	7/31/2018	359663	BOARD LUNCH	7430	7/19/2018	BOD
451	7696	CHERRY A JORDAN	Meals	13.29	7/31/2018	3127	EXPENSE REPORT	JULY/2018	7/27/2018	BOD
452	8845	SWEET KNEADS BY FGTN BAKERY	Meals	31.04	7/31/2018	360041	ROLLS/MUFFINS/DONUTS	07856061	7/31/2018	BOD
453	2625	JANET L LEKSON	Meals	111.85	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
454	2938	HENKE, CARLA S	Meals	78.40	8/31/2018	3165	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
455	3226	US BANK	Meals	53.53	8/31/2018	2009507	CC Recap-Christene D. Dodge-Ra	8/2018-CDD	8/30/2018	HIRE
456	3226	US BANK	Meals	105.62	8/31/2018	2009507	CC Recap-Kimberely A. Helleson	8/2018-KAH	8/30/2018	CUS
457	3226	US BANK	Meals	137.69	8/31/2018	2009507	CC Recap-Kimberely A. Helleson	8/2018-KAH	8/30/2018	CUS
458	3226	US BANK	Meals	92.66	8/31/2018	2009507	CC Recap-Denise D. Hrncir	8/2018-DDH	8/30/2018	WELLNESS
459	3226	US BANK	Meals	52.89	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	BOD
460	3226	US BANK	Meals	130.60	8/31/2018	2009507	CC Recap-Danielle J. Johnson	8/2018-DJJ	8/30/2018	ETS
461	3226	US BANK	Meals	217.36	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	AMS
462	3226	US BANK	Meals	17.96	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	BOD
463	3226	US BANK	Meals	22.77	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	BOD
464	3226	US BANK	Meals	56.01	8/31/2018	2009507	CC Recap-Cherry A. Jordan	8/2018-CAJ	8/30/2018	BOD
465	3226	US BANK	Meals	42.00	8/31/2018	2009507	CC Recap-Brenda K. Kadlec	8/2018-BKK	8/30/2018	ACS
466	3226	US BANK	Meals	39.28	8/31/2018	2009507	CC Recap-Bernard M. Kolnberger	8/2018-BMK	8/30/2018	USO
467	3226	US BANK	Meals	28.46	8/31/2018	2009507	CC Recap-Betty Jo A. Kiesow	8/2018-BAK	8/30/2018	NCD
468	3226	US BANK	Meals	22.83	8/31/2018	2009507	CC Recap-Craig Knudsen	8/2018-CEK	8/30/2018	ROW
469	3226	US BANK	Meals	7.49	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
470	3226	US BANK	Meals	19.99	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
471	3226	US BANK	Meals	42.33	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	8/30/2018	ECO
472	3226	US BANK	Meals	107.77	8/31/2018	2009507	CC Recap-Greg C. Miller	8/2018-GCM	8/30/2018	AMS
473	3226	US BANK	Meals	28.63	8/31/2018	2009507	CC Recap-Greg C. Miller	8/2018-GCM	8/30/2018	AMS
474	3226	US BANK	Meals	68.04	8/31/2018	2009507	CC Recap-Greg C. Miller	8/2018-GCM	8/30/2018	AMS
475	3226	US BANK	Meals	44.21	8/31/2018	2009507	CC Recap-Greg C. Miller	8/2018-GCM	8/30/2018	AMS
476	3226	US BANK	Meals	8.56	8/31/2018	2009507	CC Recap-Joseph A. Miller	8/2018-JAM	8/30/2018	CUSEVENT
477	3226	US BANK	Meals	35.97	8/31/2018	2009507	CC Recap-Stephanie M. Pederson	8/2018-SMP	8/30/2018	DSM
478	3226	US BANK	Meals	37.53	8/31/2018	2009507	CC Recap-Stephanie M. Pederson	8/2018-SMP	8/30/2018	DSM
479	3226	US BANK	Meals	11.55	8/31/2018	2009507	CC Recap-Michael D. Plutowski	8/2018-MDP	8/30/2018	DSM
480	3226	US BANK	Meals	16.37	8/31/2018	2009507	CC Recap-Randall Poulson	8/2018-RLP	8/30/2018	ETS
481	3226	US BANK	Meals	6.41	8/31/2018	2009507	CC Recap-Jeffrey L Schoenecker	8/2018-JLS	8/30/2018	AUO
482	3226	US BANK	Meals	3.98	8/31/2018	2009507	CC Recap-Julie A. Simonsen	8/2018-JAS	8/30/2018	CUSEVENT
483	3226	US BANK	Meals	3.98	8/31/2018	2009507	CC Recap-Julie A. Simonsen	8/2018-JAS	8/30/2018	CUSEVENT
484	3226	US BANK	Meals	48.21	8/31/2018	2009507	CC Recap-Daniel P. Ross	8/2018-DPR	8/30/2018	VISITS
485	3226	US BANK	Meals	87.48	8/31/2018	2009507	CC Recap-Daniel P. Ross	8/2018-DPR	8/30/2018	VISITS
486	3226	US BANK	Meals	52.17	8/31/2018	2009507	CC Recap-Sheryl K. Wutschke	8/2018-SKW	8/30/2018	CISBIL
487	3226	US BANK	Meals	23.80	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
488	3226	US BANK	Meals	6.44	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
489	3226	US BANK	Meals	32.06	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
490	3226	US BANK	Meals	17.28	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
491	3226	US BANK	Meals	26.19	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
492	3226	US BANK	Meals	10.82	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
493	3226	US BANK	Meals	12.99	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
494	3226	US BANK	Meals	18.39	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
495	3226	US BANK	Meals	18.39	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
496	3226	US BANK	Meals	20.64	8/31/2018	2009507	CC Recap-James R. Stenstrom	8/2018-JRS	8/30/2018	EDU
497	3226	US BANK	Meals	56.31	8/31/2018	2009507	CC Recap-Kevin S. Fowler	8/2018-KSF	8/30/2018	SAF
498	3226	US BANK	Meals	25.50	8/31/2018	2009507	CC Recap-Shannon M. Olson	8/2018-SMO	8/30/2018	BILL
499	3226	US BANK	Meals	40.02	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
500	3226	US BANK	Meals	30.95	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
501	3226	US BANK	Meals	38.73	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
502	3226	US BANK	Meals	5.68	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
503	3226	US BANK	Meals	35.53	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
504	3226	US BANK	Meals	45.43	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
505	3226	US BANK	Meals	24.13	8/31/2018	2009507	CC Recap-Anthony J Nobach	8/2018-AJN	8/30/2018	DIS
506	3226	US BANK	Meals	54.09	8/31/2018	2009507	CC Recap-Randy D. Ratzlaff	8/2018-RDR	8/30/2018	EDU
507	3226	US BANK	Meals	57.47	8/31/2018	2009507	CC Recap-John A. Thurmes	8/2018-JAT	8/30/2018	DIS
508	3226	US BANK	Meals	14.97	8/31/2018	2009507	CC Recap-Jackie A. Bauer	8/2018-JAB	8/30/2018	FAIRSHOW
509	3226	US BANK	Meals	151.46	8/31/2018	2009507	CC Recap-Craig C. Turner	8/2018-CCT	8/30/2018	ETS
510	*3226*	*US BANK*	*Meals*	*52.53*	*8/31/2018*	*2009507*	*CC Recap-Craig C. Turner*	*8/2018-CCT*	*8/30/2018*	*AGI2018*
511	3818	JOE A MILLER	Meals	25.00	8/31/2018	361161	EXPENSE REPORT	AUG/2018	9/11/2018	FAIRSHOW
512	5426	PAUL A TRAPP	Meals	56.40	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
513	5886	KENNETH H DANNER	Meals	32.87	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
514	7477	CLASSIC CATERING	Meals	725.25	8/31/2018	360651	BOARD LUNCH	7501	8/23/2018	BOD
515	8060	DAVID S JONES	Meals	77.13	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
516	8545	COREY M HINTZ	Meals	49.68	8/31/2018	3166	EXPENSE REPORT	AUG/2018	8/31/2018	EDU
517	8845	SWEET KNEADS BY FGTN BAKERY	Meals	30.34	8/31/2018	361024	ROLLS/DONUTS/MUFFINS	07856092	9/4/2018	BOD
518	2564	SAM'S CLUB	Meals	148.18	9/30/2018	362148	WELLNESS FAIR/CANDY/VET'S	9/2018-4731	10/16/2018	HRP
519	2564	SAM'S CLUB	Meals	76.66	9/30/2018	362148	WELLNESS FAIR/CANDY/VET'S	9/2018-4731	10/16/2018	WELLNESS
520	2564	SAM'S CLUB	Meals	46.53	9/30/2018	362148	WELLNESS FAIR/CANDY/VET'S	9/2018-4731	10/16/2018	EFUNC
521	2625	JANET L LEKSON	Meals	290.07	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
522	2938	HENKE, CARLA S	Meals	76.68	9/30/2018	3207	EXPENSE REPORT	SEP/2018	10/3/2018	LAWSON
523	3226	US BANK	Meals	27.20	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
524	3226	US BANK	Meals	36.00	9/30/2018	2009512	CC Recap-Michael G. Fosse	9/2018-MGF	10/1/2018	ACS
525	3226	US BANK	Meals	51.00	9/30/2018	2009512	CC Recap-Christene D. Dodge-Ra	9/2018-CDD	10/1/2018	HIRE
526	3226	US BANK	Meals	39.36	9/30/2018	2009512	CC Recap-Timothy J. Doherty	9/2018-TJD	10/1/2018	KEY
527	3226	US BANK	Meals	49.81	9/30/2018	2009512	CC Recap-Timothy J. Doherty	9/2018-TJD	10/1/2018	KEY
528	3226	US BANK	Meals	54.65	9/30/2018	2009512	CC Recap-Kevin S. Fowler	9/2018-KSF	10/1/2018	SAFEST
529	3226	US BANK	Meals	243.04	9/30/2018	2009512	CC Recap-Kevin S. Fowler	9/2018-KSF	10/1/2018	SAFEST
530	3226	US BANK	Meals	141.14	9/30/2018	2009512	CC Recap-Denise D. Hrncir	9/2018-DDH	10/1/2018	WELLNESS
531	3226	US BANK	Meals	11.96	9/30/2018	2009512	CC Recap-Denise D. Hrncir	9/2018-DDH	10/1/2018	WELLNESS
532	3226	US BANK	Meals	24.32	9/30/2018	2009512	CC Recap-Margaret (Peggy) P Jo	9/2018-PPJ	10/1/2018	COMMREL
533	3226	US BANK	Meals	24.59	9/30/2018	2009512	CC Recap-Margaret (Peggy) P Jo	9/2018-PPJ	10/1/2018	COMMREL
534	3226	US BANK	Meals	30.71	9/30/2018	2009512	CC Recap-Margaret (Peggy) P Jo	9/2018-PPJ	10/1/2018	COMMREL
535	3226	US BANK	Meals	37.07	9/30/2018	2009512	CC Recap-Douglas R. Larson	9/2018-DRL	10/1/2018	KEY
536	3226	US BANK	Meals	16.04	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BOD
537	3226	US BANK	Meals	107.18	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BOD
538	3226	US BANK	Meals	6.41	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	AMS
539	3226	US BANK	Meals	16.04	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BOD
540	3226	US BANK	Meals	10.69	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BOD
541	3226	US BANK	Meals	150.50	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
542	3226	US BANK	Meals	92.49	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
543	3226	US BANK	Meals	69.85	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
544	3226	US BANK	Meals	6.98	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
545	3226	US BANK	Meals	17.25	9/30/2018	2009512	CC Recap-Mark W. Lofthus	9/2018-MWL	10/1/2018	ECO
546	3226	US BANK	Meals	169.29	9/30/2018	2009512	CC Recap-Ann J. Maniaci	9/2018-AJM	10/1/2018	SAF
547	3226	US BANK	Meals	22.26	9/30/2018	2009512	CC Recap-Davin H. Peterson	9/2018-DHP	10/1/2018	ETS
548	3226	US BANK	Meals	24.87	9/30/2018	2009512	CC Recap-Jeffrey L Schoenecker	9/2018-JLS	10/1/2018	AUO
549	3226	US BANK	Meals	39.00	9/30/2018	2009512	CC Recap-Jane E. Siebenaler	9/2018-JES	10/1/2018	VISITS
550	3226	US BANK	Meals	133.98	9/30/2018	2009512	CC Recap-Grant S. Baumberger	9/2018-GSB	10/1/2018	TEC
551	3226	US BANK	Meals	149.83	9/30/2018	2009512	CC Recap-Kimberely A. Helleson	9/2018-KAH	10/1/2018	CUS
552	3226	US BANK	Meals	17.37	9/30/2018	2009512	CC Recap-Glenda Hewitt	9/2018-GLH	10/1/2018	AGI2018
553	3226	US BANK	Meals	32.70	9/30/2018	2009512	CC Recap-Glenda Hewitt	9/2018-GLH	10/1/2018	AEN
554	3226	US BANK	Meals	29.83	9/30/2018	2009512	CC Recap-Glenda Hewitt	9/2018-GLH	10/1/2018	AUO
555	3226	US BANK	Meals	212.66	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	AGI2018
556	3226	US BANK	Meals	356.11	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	AGI2018
557	3226	US BANK	Meals	475.60	9/30/2018	2009512	CC Recap-Danielle J. Johnson	9/2018-DJJ	10/1/2018	TRA
558	3226	US BANK	Meals	45.27	9/30/2018	2009512	CC Recap-Bernard M. Kolnberger	9/2018-BMK	10/1/2018	USO
559	3226	US BANK	Meals	9.36	9/30/2018	2009512	CC Recap-Bernard M. Kolnberger	9/2018-BMK	10/1/2018	TRA
560	3226	US BANK	Meals	47.96	9/30/2018	2009512	CC Recap-Bernard M. Kolnberger	9/2018-BMK	10/1/2018	TRA

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
561	3226	US BANK	Meals	12.06	9/30/2018	2009512	CC Recap-Bernard M. Kolnberger	9/2018-BMK	10/1/2018	TRA
562	3226	US BANK	Meals	29.07	9/30/2018	2009512	CC Recap-Greg C. Miller	9/2018-GCM	10/1/2018	AMS
563	3226	US BANK	Meals	136.43	9/30/2018	2009512	CC Recap-Corey S. Willert	9/2018-CSW	10/1/2018	NCD
564	3226	US BANK	Meals	64.56	9/30/2018	2009512	CC Recap-Richard M. Siebenaler	9/2018-RMS	10/1/2018	USO
565	3226	US BANK	Meals	115.72	9/30/2018	2009512	CC Recap-Sheryl K. Wutschke	9/2018-SKW	10/1/2018	METRD
566	3226	US BANK	Meals	179.20	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	ELECCAR
567	3226	US BANK	Meals	95.12	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	ELECCAR
568	3226	US BANK	Meals	2.67	9/30/2018	2009512	CC Recap-Stephanie M. Pederson	9/2018-SMP	10/1/2018	ELECCAR
569	3226	US BANK	Meals	131.08	9/30/2018	2009512	CC Recap-David S. Reinke	9/2018-DSR	10/1/2018	CISBIL
570	3226	US BANK	Meals	33.66	9/30/2018	2009512	CC Recap-David S. Reinke	9/2018-DSR	10/1/2018	CISBIL
571	3226	US BANK	Meals	12.10	9/30/2018	2009512	CC Recap-David S. Reinke	9/2018-DSR	10/1/2018	CISBIL
572	3226	US BANK	Meals	237.50	9/30/2018	2009512	CC Recap-David S. Reinke	9/2018-DSR	10/1/2018	AGI2018
573	3226	US BANK	Meals	78.00	9/30/2018	2009512	CC Recap-John A. Thurmes	9/2018-JAT	10/1/2018	DIS
574	3226	US BANK	Meals	62.26	9/30/2018	2009512	CC Recap-Craig C. Turner	9/2018-CCT	10/1/2018	ETS
575	3226	US BANK	Meals	11.94	9/30/2018	2009512	CC Recap-Craig C. Turner	9/2018-CCT	10/1/2018	REG
576	*4042*	*CRAIG TURNER*	*Meals*	*62.30*	*9/30/2018*	*361935*	*EXPENSE REPORT*	*SEP/2018*	*10/9/2018*	*AGI2018*
577	5426	PAUL A TRAPP	Meals	43.03	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
578	7477	CLASSIC CATERING	Meals	493.50	9/30/2018	361531	BOARD LUNCH 9/27/18	7566	9/25/2018	BOD
579	8060	DAVID S JONES	Meals	29.61	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
580	8207	JOHN D DEYOE	Meals	12.21	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
581	8845	SWEET KNEADS BY FGTN BAKERY	Meals	31.04	9/30/2018	361784	ROLLS/DONUTS/MUFFINS	07787238	10/2/2018	BOD
582	2564	SAM'S CLUB	Meals	300.13	10/31/2018	363226	10/2018 PURCHASES	10/2018-4731	11/15/2018	EFUNC
583	2564	SAM'S CLUB	Meals	420.57	10/31/2018	363226	10/2018 PURCHASES	10/2018-4731	11/15/2018	WELLNESS
584	2564	SAM'S CLUB	Meals	326.99	10/31/2018	363226	10/2018 PURCHASES	10/2018-4731	11/15/2018	YOUTH
585	3226	US BANK	Meals	20.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	DEYOE
586	3226	US BANK	Meals	20.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	PTRAPP
587	3226	US BANK	Meals	144.79	10/31/2018	2009520	CC Recap-Kimberely A. Helleson	10/2018-KAH	10/31/2018	CUS
588	3226	US BANK	Meals	16.10	10/31/2018	2009520	CC Recap-Margaret (Peggy) P Jo	10/2018-PPJ	10/31/2018	COMMREL
589	3226	US BANK	Meals	30.55	10/31/2018	2009520	CC Recap-Margaret (Peggy) P Jo	10/2018-PPJ	10/31/2018	COMMREL
590	3226	US BANK	Meals	33.94	10/31/2018	2009520	CC Recap-Margaret (Peggy) P Jo	10/2018-PPJ	10/31/2018	COMMREL
591	3226	US BANK	Meals	45.00	10/31/2018	2009520	CC Recap-Joseph P. Kuhn	10/2018-JPK	10/31/2018	MAI
592	3226	US BANK	Meals	67.60	10/31/2018	2009520	CC Recap-Linda L. Landwehr	10/2018-LLL	10/31/2018	MKTPLAN
593	3226	US BANK	Meals	32.92	10/31/2018	2009520	CC Recap-Mark W. Lofthus	10/2018-MWL	10/31/2018	ECO
594	3226	US BANK	Meals	34.04	10/31/2018	2009520	CC Recap-Malinda R. Mehrhoff	10/2018-MRM-1109	10/31/2018	EFUNC
595	3226	US BANK	Meals	56.18	10/31/2018	2009520	CC Recap-Ann J. Maniaci	10/2018-AJM	10/31/2018	AFS
596	3226	US BANK	Meals	339.60	10/31/2018	2009520	CC Recap-Malinda R. Mehrhoff	10/2018-MRM-1109	10/31/2018	EFUNC
597	3226	US BANK	Meals	5.55	10/31/2018	2009520	CC Recap-Malinda R. Mehrhoff	10/2018-MRM-1109	10/31/2018	WELLNESS
598	3226	US BANK	Meals	60.11	10/31/2018	2009520	CC Recap-Greg C. Miller	10/2018-GCM	10/31/2018	AMS
599	3226	US BANK	Meals	28.50	10/31/2018	2009520	CC Recap-Greg C. Miller	10/2018-GCM	10/31/2018	AMS
600	3226	US BANK	Meals	28.82	10/31/2018	2009520	CC Recap-Greg C. Miller	10/2018-GCM	10/31/2018	AMS
601	3226	US BANK	Meals	17.06	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
602	3226	US BANK	Meals	25.99	10/31/2018	2009520	CC Recap-Joseph A. Miller	10/2018-JAM	10/31/2018	BRANDING
603	3226	US BANK	Meals	62.49	10/31/2018	2009520	CC Recap-Jeffrey L Schoenecker	10/2018-JLS	10/31/2018	AUO
604	3226	US BANK	Meals	47.00	10/31/2018	2009520	CC Recap-Richard M. Siebenaler	10/2018-RMS	10/31/2018	USO
605	3226	US BANK	Meals	55.56	10/31/2018	2009520	CC Recap-Richard M. Siebenaler	10/2018-RMS	10/31/2018	USO
606	3226	US BANK	Meals	137.47	10/31/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	BOD
607	3226	US BANK	Meals	281.85	10/31/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	SAFEST
608	3226	US BANK	Meals	28.69	10/31/2018	2009520	CC Recap-Bernard M. Kolnberger	10/2018-BMK	10/31/2018	USO
609	3226	US BANK	Meals	40.64	10/31/2018	2009520	CC Recap-Bernard M. Kolnberger	10/2018-BMK	10/31/2018	USO
610	3226	US BANK	Meals	45.35	10/31/2018	2009520	CC Recap-Sheryl K. Wutschke	10/2018-SKW	10/31/2018	CIS
611	3226	US BANK	Meals	93.43	10/31/2018	2009520	CC Recap-Christene D. Dodge-Ra	10/2018-CDD	10/31/2018	HIRE
612	3226	US BANK	Meals	64.04	10/31/2018	2009520	CC Recap-David S. Reinke	10/2018-DSR	10/31/2018	AGI2018
613	3226	US BANK	Meals	47.57	10/31/2018	2009520	CC Recap-Betty Jo A. Kiesow	10/2018-BAK	10/31/2018	NCD
614	3226	US BANK	Meals	25.81	10/31/2018	2009520	CC Recap-Betty Jo A. Kiesow	10/2018-BAK	10/31/2018	LOC
615	*3226*	*US BANK*	*Meals*	*30.11*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
616	*3226*	*US BANK*	*Meals*	*58.56*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
617	*3226*	*US BANK*	*Meals*	*15.82*	*10/31/2018*	*2009520*	*CC Recap-David S. Reinke*	*10/2018-DSR*	*10/31/2018*	*AGI2018*
618	3226	US BANK	Meals	51.94	10/31/2018	2009520	CC Recap-David S. Reinke	10/2018-DSR	10/31/2018	DSM
619	3226	US BANK	Meals	16.30	10/31/2018	2009520	CC Recap-Corey S. Willert	10/2018-CSW	10/31/2018	EDU
620	3226	US BANK	Meals	78.97	10/31/2018	2009520	CC Recap-Jane E. Siebenaler	10/2018-JES	10/31/2018	KEY
621	3226	US BANK	Meals	47.77	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
622	3226	US BANK	Meals	23.63	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
623	3226	US BANK	Meals	18.75	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	DIS
624	3226	US BANK	Meals	56.04	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
625	3226	US BANK	Meals	59.28	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
626	3226	US BANK	Meals	16.27	10/31/2018	2009520	CC Recap-John A. Thurmes	10/2018-JAT	10/31/2018	EDU
627	3226	US BANK	Meals	38.29	10/31/2018	2009520	CC Recap-Craig C. Turner	10/2018-CCT	10/31/2018	ETS
628	4079	MOUNT OLIVET CONF & RETREAT CT	Meals	1,555.27	10/31/2018	362217	MARKETING RETREAT - FINAL	7979	10/18/2018	MKTPLAN
629	6745	LONGBRANCH SALOON & EATERY	Meals	1,379.66	10/31/2018	362136	TACOS/WELLNESS WEEK	OCT-11-18	10/16/2018	WELLNESS
630	7477	CLASSIC CATERING	Meals	553.49	10/31/2018	361793	ENGINEERING BREAKFAST	7587	10/3/2018	AEN
631	7477	CLASSIC CATERING	Meals	534.74	10/31/2018	362185	BOARD LUNCH	7652	10/18/2018	BOD
632	8060	DAVID S JONES	Meals	498.59	10/31/2018	3242	EXPENSE REPORT	OCT/2018	10/31/2018	JONES
633	8845	SWEET KNEADS BY FGTN BAKERY	Meals	31.10	10/31/2018	362767	ROLLS/DONUTS/CUSTARD	07859092	11/6/2018	BOD
634	2305	GERALD F PITTMAN JR	Meals	131.48	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
635	2564	SAM'S CLUB	Meals	104.09	11/30/2018	364029	11/8-11/14/18 PURCHASES	11/2018-4731	12/13/2018	EFUNC
636	2564	SAM'S CLUB	Meals	20.96	11/30/2018	364029	11/8-11/14/18 PURCHASES	11/2018-4731	12/13/2018	EFUNC
637	2564	SAM'S CLUB	Meals	31.96	11/30/2018	364029	11/8-11/14/18 PURCHASES	11/2018-4731	12/13/2018	ACS
638	2564	SAM'S CLUB	Meals	31.60	11/30/2018	364029	11/8-11/14/18 PURCHASES	11/2018-4731	12/13/2018	HIRE
639	2895	DOUGLAS R LARSON	Meals	18.73	11/30/2018	3273	EXPENSE REPORT	NOV/2018	12/4/2018	REG
640	3048	MARGARET D SCHREINER	Meals	926.18	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
641	3226	US BANK	Meals	45.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	JONES
642	3226	US BANK	Meals	46.00	11/30/2018	2009526	CC Recap-Grant S. Baumberger	11/2018-GSB	11/30/2018	SUBO
643	3226	US BANK	Meals	22.00	11/30/2018	2009526	CC Recap-Denise D. Hrncir	11/2018-DDH	11/30/2018	WELLNESS
644	3226	US BANK	Meals	40.83	11/30/2018	2009526	CC Recap-Denise D. Hrncir	11/2018-DDH	11/30/2018	HRP
645	3226	US BANK	Meals	107.22	11/30/2018	2009526	CC Recap-Denise D. Hrncir	11/2018-DDH	11/30/2018	WELLNESS
646	3226	US BANK	Meals	25.27	11/30/2018	2009526	CC Recap-Margaret (Peggy) P Jo	11/2018-PPJ	11/30/2018	COMMREL
647	3226	US BANK	Meals	52.74	11/30/2018	2009526	CC Recap-Brenda K. Kadlec	11/2018-BKK	11/30/2018	KEY
648	3226	US BANK	Meals	79.36	11/30/2018	2009526	CC Recap-Linda L. Landwehr	11/2018-LLL	11/30/2018	MKTPLAN
649	3226	US BANK	Meals	33.70	11/30/2018	2009526	CC Recap-Betty Jo A. Kiesow	11/2018-BAK	11/30/2018	NCD
650	3226	US BANK	Meals	202.40	11/30/2018	2009526	CC Recap-Ann J. Maniaci	11/2018-AJM	11/30/2018	SAF
651	3226	US BANK	Meals	27.04	11/30/2018	2009526	CC Recap-Malinda R. Mehrhoff	11/2018-MRM-6676	11/30/2018	EDU
652	3226	US BANK	Meals	3.99	11/30/2018	2009526	CC Recap-Malinda R. Mehrhoff	11/2018-MRM-1109	11/30/2018	EFUNC
653	3226	US BANK	Meals	75.53	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	CIGROUP
654	3226	US BANK	Meals	28.26	11/30/2018	2009526	CC Recap-Shannon M. Olson	11/2018-SMO	11/30/2018	CIS
655	3226	US BANK	Meals	35.49	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
656	3226	US BANK	Meals	35.66	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
657	3226	US BANK	Meals	390.80	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	CIGROUP
658	3226	US BANK	Meals	19.38	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
659	3226	US BANK	Meals	13.05	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
660	3226	US BANK	Meals	26.25	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
661	3226	US BANK	Meals	9.71	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
662	3226	US BANK	Meals	21.19	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
663	3226	US BANK	Meals	21.57	11/30/2018	2009526	CC Recap-Jane E. Siebenaler	11/2018-JES	11/30/2018	EDU
664	3226	US BANK	Meals	17.96	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	AGI
665	3226	US BANK	Meals	52.83	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	EDU
666	3226	US BANK	Meals	155.76	11/30/2018	2009526	CC Recap-Sheryl K. Wutschke	11/2018-SKW	11/30/2018	METRD
667	3226	US BANK	Meals	64.80	11/30/2018	2009526	CC Recap-Craig C Turner	11/2018-CCT	11/30/2018	ETS
668	3226	US BANK	Meals	354.55	11/30/2018	2009526	CC Recap-Kevin S. Fowler	11/2018-KSF	11/30/2018	STMTGS
669	3226	US BANK	Meals	200.77	11/30/2018	2009526	CC Recap-Kevin S. Fowler	11/2018-KSF	11/30/2018	STMTGS
670	3226	US BANK	Meals	293.42	11/30/2018	2009526	CC Recap-Kevin S. Fowler	11/2018-KSF	11/30/2018	STMTGS
671	3226	US BANK	Meals	43.87	11/30/2018	2009526	CC Recap-Kevin S. Fowler	11/2018-KSF	11/30/2018	SAF
672	3226	US BANK	Meals	267.11	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	BOD

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
673	3226	US BANK	Meals	11.76	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	BOD
674	3226	US BANK	Meals	83.67	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	BOD
675	3226	US BANK	Meals	109.06	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	BOD
676	3226	US BANK	Meals	79.74	11/30/2018	2009526	CC Recap-Danielle J. Johnson	11/2018-DJJ	11/30/2018	AGI2018
677	3226	US BANK	Meals	174.13	11/30/2018	2009526	CC Recap-Danielle J. Johnson	11/2018-DJJ	11/30/2018	EDU
678	3226	US BANK	Meals	61.99	11/30/2018	2009526	CC Recap-Joseph P. Kuhn	11/2018-JPK	11/30/2018	MAI
679	3226	US BANK	Meals	22.78	11/30/2018	2009526	CC Recap-Kimberely A. Helleson	11/2018-KAH	11/30/2018	CUS
680	3226	US BANK	Meals	11.98	11/30/2018	2009526	CC Recap-Glenda Hewitt	11/2018-GLH	11/30/2018	AEN
681	3226	US BANK	Meals	81.35	11/30/2018	2009526	CC Recap-Glenda Hewitt	11/2018-GLH	11/30/2018	AEN
682	3226	US BANK	Meals	37.33	11/30/2018	2009526	CC Recap-Glenda Hewitt	11/2018-GLH	11/30/2018	AEN
683	3226	US BANK	Meals	15.16	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
684	3226	US BANK	Meals	17.29	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
685	3226	US BANK	Meals	32.88	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
686	3226	US BANK	Meals	33.96	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
687	3226	US BANK	Meals	39.24	11/30/2018	2009526	CC Recap-Mark W. Lofthus	11/2018-MWL	11/30/2018	ECO
688	3226	US BANK	Meals	73.76	11/30/2018	2009526	CC Recap-Daniel P. Ross	11/2018-DPR	11/30/2018	VISITS
689	3226	US BANK	Meals	33.39	11/30/2018	2009526	CC Recap-Davin H. Peterson	11/2018-DHP	11/30/2018	ETS
690	3226	US BANK	Meals	148.27	11/30/2018	2009526	CC Recap-Christene D. Dodge-Ra	11/2018-CDD	11/30/2018	HIRE
691	3226	US BANK	Meals	41.47	11/30/2018	2009526	CC Recap-Bernard M. Kolnberger	11/2018-BMK	11/30/2018	USO
692	3226	US BANK	Meals	38.60	11/30/2018	2009526	CC Recap-Bernard M. Kolnberger	11/2018-BMK	11/30/2018	USO
693	3226	US BANK	Meals	24.22	11/30/2018	2009526	CC Recap-Anthony J Nobach	11/2018-AJN	11/30/2018	DIS
694	3226	US BANK	Meals	33.39	11/30/2018	2009526	CC Recap-Anthony J Nobach	11/2018-AJN	11/30/2018	DIS
695	3226	US BANK	Meals	66.00	11/30/2018	2009526	CC Recap-Timothy J. Doherty	11/2018-TJD	11/30/2018	KEY
696	4546	ROTARY CLUB OF APPLE VALLEY	Meals	150.00	11/30/2018	363681	G MILLER 4/1/18-6/30/18	1601	12/4/2018	AMS
697	4546	ROTARY CLUB OF APPLE VALLEY	Meals	162.50	11/30/2018	363681	G MILLER 7/1/18-9/30/18	1671	12/4/2018	AMS
698	4546	ROTARY CLUB OF APPLE VALLEY	Meals	150.00	11/30/2018	363681	G MILLER 10/1/18-12/31/18	1716	12/4/2018	AMS
699	4919	CLAY VAN DE BOGART	Meals	24.91	11/30/2018	363764	EXPENSE REPORT	NOV/2018	12/6/2018	VAN
700	7138	GERI L WACHTER	Meals	38.92	11/30/2018	3264	EXPENSE REPORT	NOV/2018	11/21/2018	TIMETRACK
701	7477	CLASSIC CATERING	Meals	469.93	11/30/2018	363375	BOARD LUNCH	7765	11/20/2018	BOD
702	7795	CHRIS CAKES	Meals	1,137.62	11/30/2018	362742	PANCAKE BRKFST/DAK CARES	11/2018-DAKCARES	11/6/2018	EFUNC
703	8060	DAVID S JONES	Meals	228.40	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
704	8489	ADAM L MULDER	Meals	98.64	11/30/2018	363406	EXPENSE REPORT	NOV/2018	11/20/2018	ACTSAF
705	8845	SWEET KNEADS BY FGTN BAKERY	Meals	29.10	11/30/2018	363684	ROLLS/MUFFINS/DONUTS	08039241	12/4/2018	BOD
706	2564	SAM'S CLUB	Meals	117.50	12/31/2018	364815	12/7/18-12/20/18 PURCHASES	12/2018-4731	1/15/2019	SANTA
707	2564	SAM'S CLUB	Meals	62.50	12/31/2018	364815	12/7/18-12/20/18 PURCHASES	12/2018-4731	1/15/2019	BOD
708	3226	US BANK	Meals	40.01	12/31/2018	2009534	CC Recap-Jackie A. Bauer	12/2018-JAB	12/31/2018	DSM
709	3226	US BANK	Meals	307.09	12/31/2018	2009534	CC Recap-Jackie A. Bauer	12/2018-JAB	12/31/2018	DSM
710	3226	US BANK	Meals	30.07	12/31/2018	2009534	CC Recap-Jackie A. Bauer	12/2018-JAB	12/31/2018	DSM
711	3226	US BANK	Meals	267.21	12/31/2018	2009534	CC Recap-Jackie A. Bauer	12/2018-JAB	12/31/2018	DSM
712	3226	US BANK	Meals	130.94	12/31/2018	2009534	CC Recap-Jay R. Bauer	12/2018-JRB	12/31/2018	USO
713	3226	US BANK	Meals	59.06	12/31/2018	2009534	CC Recap-James L. Bormann	12/2018-JLB	12/31/2018	USO
714	3226	US BANK	Meals	79.26	12/31/2018	2009534	CC Recap-Timothy J. Doherty	12/2018-TJD	12/31/2018	KEY
715	3226	US BANK	Meals	40.00	12/31/2018	2009534	CC Recap-Kevin S. Fowler	12/2018-KSF	12/31/2018	STMTGS
716	3226	US BANK	Meals	23.13	12/31/2018	2009534	CC Recap-Kevin S. Fowler	12/2018-KSF	12/31/2018	EDU
717	3226	US BANK	Meals	16.83	12/31/2018	2009534	CC Recap-Kevin S. Fowler	12/2018-KSF	12/31/2018	EDU
718	3226	US BANK	Meals	938.77	12/31/2018	2009534	CC Recap-Christene D. Dodge-Ra	12/2018-CDD	12/31/2018	SANTA
719	3226	US BANK	Meals	(20.00)	12/31/2018	2009534	CC Recap-Christene D. Dodge-Ra	12/2018-CDD	12/31/2018	SANTA
720	3226	US BANK	Meals	46.30	12/31/2018	2009534	CC Recap-Christene D. Dodge-Ra	12/2018-CDD	12/31/2018	HIRE
721	3226	US BANK	Meals	40.00	12/31/2018	2009534	CC Recap-Kimberely A. Helleson	12/2018-KAH	12/31/2018	CUS
722	3226	US BANK	Meals	189.47	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
723	3226	US BANK	Meals	61.03	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
724	3226	US BANK	Meals	31.00	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
725	3226	US BANK	Meals	44.96	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
726	3226	US BANK	Meals	10.69	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
727	3226	US BANK	Meals	12.46	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
728	3226	US BANK	Meals	9.45	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
729	3226	US BANK	Meals	374.94	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	AEN
730	3226	US BANK	Meals	59.19	12/31/2018	2009534	CC Recap-Glenda Hewitt	12/2018-GLH	12/31/2018	WELLNESS
731	3226	US BANK	Meals	34.20	12/31/2018	2009534	CC Recap-Denise D. Hrncir	12/2018-DDH	12/31/2018	HRP
732	3226	US BANK	Meals	33.56	12/31/2018	2009534	CC Recap-Denise D. Hrncir	12/2018-DDH	12/31/2018	HRP
733	3226	US BANK	Meals	9.91	12/31/2018	2009534	CC Recap-Patrick M Hughes	12/2018-PMH	12/31/2018	EDU
734	3226	US BANK	Meals	16.66	12/31/2018	2009534	CC Recap-Patrick M Hughes	12/2018-PMH	12/31/2018	EDU
735	3226	US BANK	Meals	5.58	12/31/2018	2009534	CC Recap-Patrick M Hughes	12/2018-PMH	12/31/2018	EDU
736	3226	US BANK	Meals	75.60	12/31/2018	2009534	CC Recap-Danielle J. Johnson	12/2018-DJJ	12/31/2018	AEN
737	3226	US BANK	Meals	38.90	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
738	3226	US BANK	Meals	27.92	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
739	3226	US BANK	Meals	14.56	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
740	3226	US BANK	Meals	443.78	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	COMMREL
741	3226	US BANK	Meals	107.78	12/31/2018	2009534	CC Recap-Cherry A. Jordan	12/2018-CAJ	12/31/2018	BOD
742	3226	US BANK	Meals	5.29	12/31/2018	2009534	CC Recap-Cherry A. Jordan	12/2018-CAJ	12/31/2018	BOD
743	3226	US BANK	Meals	25.61	12/31/2018	2009534	CC Recap-Cherry A. Jordan	12/2018-CAJ	12/31/2018	BOD
744	3226	US BANK	Meals	20.34	12/31/2018	2009534	CC Recap-Cherry A. Jordan	12/2018-CAJ	12/31/2018	BOD
745	3226	US BANK	Meals	23.33	12/31/2018	2009534	CC Recap-Betty Jo A. Kiesow	12/2018-BAK	12/31/2018	NCD
746	3226	US BANK	Meals	52.40	12/31/2018	2009534	CC Recap-Bernard M. Kolnberger	12/2018-BMK	12/31/2018	USO
747	3226	US BANK	Meals	64.31	12/31/2018	2009534	CC Recap-Joseph P. Kuhn	12/2018-JPK	12/31/2018	MAI
748	3226	US BANK	Meals	20.83	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
749	3226	US BANK	Meals	11.63	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
750	3226	US BANK	Meals	10.96	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
751	3226	US BANK	Meals	62.52	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
752	3226	US BANK	Meals	16.80	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
753	3226	US BANK	Meals	7.49	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
754	3226	US BANK	Meals	28.84	12/31/2018	2009534	CC Recap-Mark W. Lofthus	12/2018-MWL	12/31/2018	ECO
755	3226	US BANK	Meals	10.85	12/31/2018	2009534	CC Recap-Ann J. Maniaci	12/2018-AJM	12/31/2018	AFS
756	3226	US BANK	Meals	279.01	12/31/2018	2009534	CC Recap-Ann J. Maniaci	12/2018-AJM	12/31/2018	AFS
757	3226	US BANK	Meals	31.05	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	REG
758	3226	US BANK	Meals	43.76	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	REG
759	3226	US BANK	Meals	70.92	12/31/2018	2009534	CC Recap-Douglas R. Larson	12/2018-DRL	12/31/2018	POWSUP
760	3226	US BANK	Meals	20.12	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-6676	12/31/2018	HIRE
761	3226	US BANK	Meals	32.59	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	HRP
762	3226	US BANK	Meals	16.81	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	HIRE
763	3226	US BANK	Meals	35.23	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	SANTA
764	3226	US BANK	Meals	6.81	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	SANTA
765	3226	US BANK	Meals	32.22	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	HIRE
766	3226	US BANK	Meals	83.16	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	HRP
767	3226	US BANK	Meals	37.44	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	ACTSAF
768	3226	US BANK	Meals	83.88	12/31/2018	2009534	CC Recap-Malinda R. Mehrhoff	12/2018-MRM-1109	12/31/2018	ACTSAF
769	3226	US BANK	Meals	50.29	12/31/2018	2009534	CC Recap-Greg C. Miller	12/2018-GCM	12/31/2018	AMS
770	3226	US BANK	Meals	532.31	12/31/2018	2009534	CC Recap-Greg C. Miller	12/2018-GCM	12/31/2018	AMS
771	3226	US BANK	Meals	33.26	12/31/2018	2009534	CC Recap-Greg C. Miller	12/2018-GCM	12/31/2018	AMS
772	3226	US BANK	Meals	24.32	12/31/2018	2009534	CC Recap-Daniel P. Ross	12/2018-DPR	12/31/2018	VISITS
773	3226	US BANK	Meals	19.01	12/31/2018	2009534	CC Recap-Daniel P. Ross	12/2018-DPR	12/31/2018	VISITS
774	3226	US BANK	Meals	53.98	12/31/2018	2009534	CC Recap-Daniel P. Ross	12/2018-DPR	12/31/2018	VISITS
775	3226	US BANK	Meals	28.66	12/31/2018	2009534	CC Recap-George D. Schmaus	12/2018-GDS	12/31/2018	USO
776	3226	US BANK	Meals	62.17	12/31/2018	2009534	CC Recap-Thomas E. Schmitz	12/2018-TES	12/31/2018	NCD
777	3226	US BANK	Meals	52.37	12/31/2018	2009534	CC Recap-Jeffrey D Schultz	12/2018-JDS	12/31/2018	EDU
778	3226	US BANK	Meals	18.06	12/31/2018	2009534	CC Recap-Julie A Simonsen	12/2018-JAS	12/31/2018	ECO
779	3226	US BANK	Meals	389.64	12/31/2018	2009534	CC Recap-Julie A Simonsen	12/2018-JAS	12/31/2018	ECO
780	3226	US BANK	Meals	77.15	12/31/2018	2009534	CC Recap-Corey S. Willert	12/2018-CSW	12/31/2018	NCD
781	3226	US BANK	Meals	65.38	12/31/2018	2009534	CC Recap-Sheryl K. Wutschke	12/2018-SKW	12/31/2018	BILL
782	3226	US BANK	Meals	80.91	12/31/2018	2009534	CC Recap-Sheryl K. Wutschke	12/2018-SKW	12/31/2018	BILL
783	3226	US BANK	Meals	90.50	12/31/2018	2009534	CC Recap-Sheryl K. Wutschke	12/2018-SKW	12/31/2018	ACTSAF
784	3226	US BANK	Meals	140.00	12/31/2018	2009534	CC Recap-Sheryl K. Wutschke	12/2018-SKW	12/31/2018	METRD

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
785	3226	US BANK	Meals	98.13	12/31/2018	2009534	CC Recap-Richard M. Siebenaler	12/2018-RMS	12/31/2018	USO
786	3227	JUDITH H KIMMES	Meals	80.00	12/31/2018	3307	EXPENSE REPORT	DEC/2018	12/28/2018	KIMMES
787	6530	RANDY M OLSON	Meals	53.95	12/31/2018	3295	EXPENSE REPORT	DEC/2018	12/14/2018	BUDGET
788	7174	TROPHY HOUSE	Meals	534.00	12/31/2018	364415	RANDOLPH/HAMP FIRE DEP	2018-HRFD	12/27/2018	SPIRIT
789	7477	CLASSIC CATERING	Meals	607.05	12/31/2018	363990	BOARD LUNCH	7871	12/13/2018	BOD
790	7903	THOMAS RISTE	Meals	90.00	12/31/2018	3312	EXPENSE REPORT	DEC/2018	12/28/2018	FIN
791	8060	DAVID S JONES	Meals	51.57	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
792	8845	SWEET KNEADS BY FGTN BAKERY	Meals	26.85	12/31/2018	364034	ROLLS/DONUTS/MUFFINS	08028351	12/13/2018	DSM
793	8845	SWEET KNEADS BY FGTN BAKERY	Meals	26.85	12/31/2018	364034	ROLLS/DONUTS/MUFFINS	08028354	12/13/2018	DSM
794	8845	SWEET KNEADS BY FGTN BAKERY	Meals	29.10	12/31/2018	364411	ASST ROLLS/DONUTS/MUFFINS	08028372	12/27/2018	BOD
		Total Company - Meals		**$ 68,525.52**	**$ -**					
795	2752	RODNEY A RAYMOND	Meal Allowances	28.00	1/31/2018	355837	MEAL REIMBRSMNT	JAN-18-18	2/1/2018	COLLCTEXP
796	2765	MARK J BOEGEMAN	Meal Allowances	15.00	1/31/2018	355297	MEAL REIMBRSMNT	JAN-6-18	1/16/2018	MAI
797	2765	MARK J BOEGEMAN	Meal Allowances	28.00	1/31/2018	355749	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
798	2787	JEFFREY W EWANIKA	Meal Allowances	28.00	1/31/2018	355307	MEAL REIMBRSMNT	JAN-3-18	1/16/2018	MAI
799	2790	SHANE KLOTZ	Meal Allowances	84.00	1/31/2018	355830	MEAL REIMBRSMNT	JAN-24-18	2/1/2018	MAI
800	2815	MARK R MATTHEES	Meal Allowances	28.00	1/31/2018	355769	MEAL REIMBRSMNT	JAN-14-18	1/30/2018	MAI
801	2815	MARK R MATTHEES	Meal Allowances	28.00	1/31/2018	355769	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
802	2941	ERIC C GEHRKE	Meal Allowances	99.00	1/31/2018	355312	MEAL REIMBRSMNT	JAN-10-18	1/16/2018	MAI
803	2941	ERIC C GEHRKE	Meal Allowances	28.00	1/31/2018	355757	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
804	4159	STEPHANIE RISTOW	Meal Allowances	56.00	1/31/2018	355121	MEAL REMBRSMNT	JAN-5-18	1/9/2018	CUS
805	4159	STEPHANIE RISTOW	Meal Allowances	28.00	1/31/2018	355486	MEAL REIMBRSMNT	JAN-12-18	1/18/2018	CUS
806	4424	JOSH RAYMOND	Meal Allowances	28.00	1/31/2018	355780	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
807	4424	JOSH RAYMOND	Meal Allowances	56.00	1/31/2018	355933	MEAL REIMBRSMNT	JAN-30-18	2/6/2018	MAI
808	4695	ANNE M RAYMOND	Meal Allowances	28.00	1/31/2018	355484	MEAL REIMBRSMNT	JAN-11-18	1/18/2018	CASH
809	4905	JACOB MAJESKI	Meal Allowances	28.00	1/31/2018	355767	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
810	5171	NICHOLAS M VOUGHT	Meal Allowances	28.00	1/31/2018	355343	MEAL REIMBRSMNT	JAN-3-18	1/16/2018	MAI
811	5171	NICHOLAS M VOUGHT	Meal Allowances	28.00	1/31/2018	355791	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
812	6129	COLE C MCWATERS	Meal Allowances	15.00	1/31/2018	355324	MEAL REIMBRSMNT	JAN-6-18	1/16/2018	MAI
813	6321	CASEY P O'BRIEN	Meal Allowances	71.00	1/31/2018	355778	MEAL REIMBRSMNT	JAN-19-18	1/30/2018	EDU
814	6418	KURT BECHEL	Meal Allowances	71.00	1/31/2018	2907	MEAL REIMBRSMNT	JAN-19-18	1/31/2018	EDU
815	7024	KYLE A SCHAFER	Meal Allowances	71.00	1/31/2018	355787	MEAL REIMBRSMNT	JAN-19-18	1/30/2018	EDU
816	7024	KYLE A SCHAFER	Meal Allowances	28.00	1/31/2018	355787	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
817	7817	KENT P HOHBACH	Meal Allowances	28.00	1/31/2018	355762	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
818	8095	SHANE J THOMPSON	Meal Allowances	28.00	1/31/2018	355789	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
819	8096	PATRICK M EMOND	Meal Allowances	28.00	1/31/2018	355754	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
820	8096	PATRICK M EMOND	Meal Allowances	66.00	1/31/2018	355912	MEAL REIMBRSMNT	JAN-30-18	2/6/2018	MAI
821	8097	LUCAS M WAXON	Meal Allowances	127.00	1/31/2018	355592	MEAL REIMBRSMNT	JAN-10-18	1/23/2018	MAI
822	8098	JORDAN L SAUNDERS	Meal Allowances	71.00	1/31/2018	355786	MEAL REIMBRSMNT	JAN-19-18	1/30/2018	EDU
823	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	1/31/2018	355786	MEAL REIMBRSMNT	JAN-22-18	1/30/2018	MAI
824	8379	JOSEPH M LODERMEIER	Meal Allowances	84.00	1/31/2018	355766	MEAL REIMBRSMNT	JAN-24-18	1/30/2018	MAI
825	8488	JOSEPH L MERHAR	Meal Allowances	28.00	1/31/2018	355477	MEAL REIMBRSMNT	JAN-4-18	1/18/2018	COLLCTEXP
826	8488	JOSEPH L MERHAR	Meal Allowances	84.00	1/31/2018	355477	MEAL REIMBRSMNT	JAN-11-18	1/18/2018	COLLCTEXP
827	8488	JOSEPH L MERHAR	Meal Allowances	28.00	1/31/2018	355771	MEAL REIMBURSMNT	JAN-24-18	1/30/2018	COLLCTEXP
828	8722	STEPHEN BARBER	Meal Allowances	28.00	1/31/2018	355153	MEAL REIMBRSMNT	JAN-5-18	1/11/2018	COLLCTEXP
829	2765	MARK J BOEGEMAN	Meal Allowances	10.00	2/28/2018	356359	MEAL REIMBRSMNT	FEB-3-18	2/27/2018	MAI
830	2789	DEAN C JABLONSKI	Meal Allowances	122.00	2/28/2018	356507	MEAL REIMBRSMNT	FEB-27-18	3/6/2018	MAI
831	2793	DANIEL W NICKLAY	Meal Allowances	28.00	2/28/2018	356389	MEAL REIMBRSMNT	FEB-11-18	2/27/2018	MAI
832	2830	RANDY D RATZLAFF	Meal Allowances	28.00	2/28/2018	356231	MEAL REIMBRSMNT	FEB-14-18	2/20/2018	COLLCTEXP
833	2830	RANDY D RATZLAFF	Meal Allowances	28.00	2/28/2018	356455	MEAL REIMBRSMNT	FEB-26-18	3/1/2018	COLLCTEXP
834	2946	JAY R BAUER	Meal Allowances	112.00	2/28/2018	2943	MEAL REIMBRSMNT	FEB-20-18	2/28/2018	MAI
835	4159	STEPHANIE RISTOW	Meal Allowances	28.00	2/28/2018	356121	MEAL REIMBURSMNT	FEB-12-18	2/15/2018	CUS
836	4695	ANNE M RAYMOND	Meal Allowances	28.00	2/28/2018	355997	MEAL REIMBRSMNT	FEB-5-18	2/8/2018	CUS
837	6129	COLE C MCWATERS	Meal Allowances	84.00	2/28/2018	356385	MEAL REIMBRSMNT	FEB-20-18	2/27/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
838	6321	CASEY P O'BRIEN	Meal Allowances	122.00	2/28/2018	356516	MEAL REIMBRSMNT	FEB-27-18	3/6/2018	MAI
839	6701	BRANDON LUNDE	Meal Allowances	28.00	2/28/2018	356383	MEAL REIMBRSMNT	FEB-11-18	2/27/2018	MAI
840	6796	SHEILA FLODIN	Meal Allowances	28.00	2/28/2018	356103	MEAL REIMBURSMNT	FEB-12-18	2/15/2018	CUS
841	7818	JADDE MALSZYCKI	Meal Allowances	28.00	2/28/2018	356384	MEAL REIMBRSMNT	FEB-20-18	2/27/2018	MAI
842	8098	JORDAN L SAUNDERS	Meal Allowances	10.00	2/28/2018	356401	MEAL REIMBRSMNT	FEB-3-18	2/27/2018	MAI
843	8379	JOSEPH M LODERMEIER	Meal Allowances	28.00	2/28/2018	356382	MEAL REIMBRSMNT	FEB-17-18	2/27/2018	MAI
844	8722	STEPHEN BARBER	Meal Allowances	28.00	2/28/2018	356206	MEAL REIMBRSMNT	FEB-15-18	2/20/2018	COLLCTEXP
845	4159	STEPHANIE RISTOW	Meal Allowances	28.00	3/30/2018	357165	MEAL REIMBRSMNT	MAR-23-18	4/10/2018	CUS
846	2769	GEORGE D SCHMAUS	Meal Allowances	58.00	3/31/2018	356675	MEAL REIMBRSMNT	MAR-5-18	3/13/2018	MAI
847	2769	GEORGE D SCHMAUS	Meal Allowances	28.00	3/31/2018	356917	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
848	2781	KYLE M SHAY	Meal Allowances	28.00	3/31/2018	357074	MEAL REIMBRSMNT	MAR-30-18	4/5/2018	TRA
849	2786	STEVEN W COLE	Meal Allowances	53.00	3/31/2018	2981	MEAL REIMBRSMNT	MAR-13-18	3/28/2018	MAI
850	2796	ANDREW F SCHRUPP	Meal Allowances	99.00	3/31/2018	3003	MEAL REIMBRSMNT	MAR-28-18	4/4/2018	MAI
851	4159	STEPHANIE RISTOW	Meal Allowances	28.00	3/31/2018	356521	MEAL REIMBRSMNT	MAR-1-18	3/6/2018	CUS
852	4159	STEPHANIE RISTOW	Meal Allowances	28.00	3/31/2018	356868	MEAL REIMBRSMNT	MAR-8-18	3/22/2018	CUS
853	4159	STEPHANIE RISTOW	Meal Allowances	28.00	3/31/2018	356868	MEAL REIMBRSMNT	MAR-12-18	3/22/2018	CUS
854	4905	JACOB MAJESKI	Meal Allowances	56.00	3/31/2018	356903	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
855	5171	NICHOLAS M VOUGHT	Meal Allowances	155.00	3/31/2018	356925	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
856	6412	GREG S NELSON	Meal Allowances	28.00	3/31/2018	356907	MEAL REIMBRSMNT	MAR-17-18	3/27/2018	MAI
857	6412	GREG S NELSON	Meal Allowances	71.00	3/31/2018	357000	MEAL REIMBRSMNT	MAR-28-18	4/3/2018	MAI
858	6796	SHEILA FLODIN	Meal Allowances	56.00	3/31/2018	356788	MEAL REIMBURSEMENT	MAR-13-18	3/20/2018	CUS
859	6796	SHEILA FLODIN	Meal Allowances	28.00	3/31/2018	356940	MEAL REIMBRSMNT	MAR-26-18	3/29/2018	CUS
860	7024	KYLE A SCHAFER	Meal Allowances	28.00	3/31/2018	356916	MEAL REIMBRSMNT	MAR-17-18	3/27/2018	MAI
861	7056	TIMOTHY D VANDERLINDE	Meal Allowances	28.00	3/31/2018	356923	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
862	8095	SHANE J THOMPSON	Meal Allowances	10.00	3/31/2018	356920	MEAL REIMBRSMNT	MAR-10-18	3/27/2018	MAI
863	8095	SHANE J THOMPSON	Meal Allowances	56.00	3/31/2018	356920	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
864	8097	LUCAS M WAXON	Meal Allowances	15.00	3/31/2018	356681	MEAL REIMBRSMNT	MAR-3-18	3/13/2018	MAI
865	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	3/31/2018	356915	MEAL REIMBRSMNT	MAR-19-18	3/27/2018	MAI
866	8424	TRAVIS J FREESE	Meal Allowances	58.00	3/31/2018	356660	MEAL REIMBRSMNT	MAR-5-18	3/13/2018	MAI
867	8488	JOSEPH L MERHAR	Meal Allowances	28.00	3/31/2018	356859	MEAL REIMBRSMNT	MAR-13-18	3/22/2018	COLLCTEXP
868	8719	SCOTT B WERNER	Meal Allowances	28.00	3/31/2018	356528	MEAL REIMBRSMNT	MAR-1-18	3/6/2018	COLLCTEXP
869	2749	KEVIN LEE JOHNSON	Meal Allowances	10.00	4/30/2018	357354	MEAL REIMBRSMNT	APR-14-18	4/24/2018	MAI
870	2765	MARK J BOEGEMAN	Meal Allowances	25.00	4/30/2018	357334	MEAL REIMBRSMNT	APR-14-18	4/24/2018	MAI
871	2769	GEORGE D SCHMAUS	Meal Allowances	10.00	4/30/2018	357965	MEAL REIMBRSMNT	MAY-4-18	5/10/2018	MAI
872	2781	KYLE M SHAY	Meal Allowances	28.00	4/30/2018	357428	MEAL REIMBURSEMENT	APR-10-18	4/26/2018	TRA
873	2781	KYLE M SHAY	Meal Allowances	56.00	4/30/2018	357967	MEAL REIMBRSMNT	MAY-4-18	5/10/2018	TRA
874	2787	JEFFREY W EWANIKA	Meal Allowances	99.00	4/30/2018	357344	MEAL REIMBRSMNT	APR-3-18	4/24/2018	MAI
875	2789	DEAN C JABLONSKI	Meal Allowances	28.00	4/30/2018	357885	MEAL REIMBRSMNT	APR-30-18	5/8/2018	MAI
876	2790	SHANE KLOTZ	Meal Allowances	28.00	4/30/2018	357357	MEAL REIMBRSMNT	APR-9-18	4/24/2018	MAI
877	2790	SHANE KLOTZ	Meal Allowances	137.00	4/30/2018	357943	MEAL REIMBRSMNT	APR-24-18	5/10/2018	MAI
878	2809	PAUL G KEHRER	Meal Allowances	10.00	4/30/2018	357356	MEAL REIMBRSMNT	APR-14-18	4/24/2018	MAI
879	2815	MARK R MATTHEES	Meal Allowances	38.00	4/30/2018	357950	MEAL REIMBRSMNT	APR-30-18	5/10/2018	MAI
880	2815	MARK R MATTHEES	Meal Allowances	28.00	4/30/2018	357950	MEAL REIMBRSMNT	MAY-1-18	5/10/2018	MAI
881	2941	ERIC C GEHRKE	Meal Allowances	28.00	4/30/2018	357347	MEAL REIMBRSMNT	APR-9-18	4/24/2018	MAI
882	2941	ERIC C GEHRKE	Meal Allowances	160.00	4/30/2018	357880	MEAL REIMBRSMNT	APR-18-18	5/8/2018	MAI
883	2941	ERIC C GEHRKE	Meal Allowances	10.00	4/30/2018	357928	MEAL REIMBRSMNT	MAY-4-18	5/10/2018	MAI
884	2946	JAY R BAUER	Meal Allowances	99.00	4/30/2018	3018	MEAL REIMBRSMNT	APR-9-18	4/25/2018	MAI
885	2956	JANET M ZIMMER	Meal Allowances	28.00	4/30/2018	357174	MEAL REIMBRSMNT	FEB-20-18	4/10/2018	GENMT
886	2956	JANET M ZIMMER	Meal Allowances	28.00	4/30/2018	357323	MEAL REIMBRSMNT	APR-14-18	4/19/2018	SUBTRAN
887	2956	JANET M ZIMMER	Meal Allowances	28.00	4/30/2018	357323	MEAL REIMBRSMNT	APR-15-18	4/19/2018	SUBTRAN
888	4905	JACOB MAJESKI	Meal Allowances	28.00	4/30/2018	357893	MEAL REIMBRSMNT	APR-18-18	5/8/2018	MAI
889	5209	BLOHM, DARYL B	Meal Allowances	28.00	4/30/2018	357142	MEAL REIMBRSMNT	APR-2-18	4/10/2018	SUBTRAN
890	6129	COLE C MCWATERS	Meal Allowances	25.00	4/30/2018	357360	MEAL REIMBRSMNT	APR-14-18	4/24/2018	MAI
891	6418	KURT BECHEL	Meal Allowances	66.00	4/30/2018	3043	MEAL REIMBRSMNT	MAY-1-18	5/9/2018	MAI
892	6796	SHEILA FLODIN	Meal Allowances	28.00	4/30/2018	357152	MEAL REIMBRSMNT	APR-5-18	4/10/2018	CUS
893	6796	SHEILA FLODIN	Meal Allowances	28.00	4/30/2018	357228	MEAL REIMBRSMNT	APR-9-18	4/17/2018	CUS

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
894	6796	SHEILA FLODIN	Meal Allowances	28.00	4/30/2018	357407	MEAL REIMBURSEMENT	APR-23-18	4/26/2018	CUS
895	7024	KYLE A SCHAFER	Meal Allowances	99.00	4/30/2018	357373	MEAL REIMBRSMNT	APR-9-18	4/24/2018	MAI
896	7024	KYLE A SCHAFER	Meal Allowances	10.00	4/30/2018	357373	MEAL REIMBRSMNT	APR-14-18	4/24/2018	MAI
897	7056	TIMOTHY D VANDERLINDE	Meal Allowances	28.00	4/30/2018	357380	MEAL REIMBRSMNT	APR-8-18	4/24/2018	MAI
898	7332	MCKENNON M VANDERVEEN	Meal Allowances	28.00	4/30/2018	357170	MEAL REIMBRSMNT	FEB-20-18	4/10/2018	GENMT
899	7332	MCKENNON M VANDERVEEN	Meal Allowances	28.00	4/30/2018	357318	MEAL REIMBRSMNT	APR-14-18	4/19/2018	SUBTRAN
900	7332	MCKENNON M VANDERVEEN	Meal Allowances	28.00	4/30/2018	357318	MEAL REIMBRSMNT	APR-15-18	4/19/2018	SUBTRAN
901	7818	JADDE MALSZYCKI	Meal Allowances	48.00	4/30/2018	357949	MEAL REIMBRSMNT	MAY-6-18	5/10/2018	MAI
902	7974	KYLE J R RYMAN	Meal Allowances	160.00	4/30/2018	357899	MEAL REIMBRSMNT	APR-18-18	5/8/2018	MAI
903	8095	SHANE J THOMPSON	Meal Allowances	28.00	4/30/2018	357378	MEAL REIMBRSMNT	MAR-31-18	4/24/2018	MAI
904	8095	SHANE J THOMPSON	Meal Allowances	53.00	4/30/2018	357903	MEAL REIMBRSMNT	APR-24-18	5/8/2018	MAI
905	8096	PATRICK M EMOND	Meal Allowances	66.00	4/30/2018	357343	MEAL REIMBRSMNT	APR-3-18	4/24/2018	MAI
906	8096	PATRICK M EMOND	Meal Allowances	28.00	4/30/2018	357875	MEAL REIMBRSMNT	APR-18-18	5/8/2018	MAI
907	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	4/30/2018	357900	MEAL REIMBRSMNT	APR-9-18	5/8/2018	MAI
908	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	4/30/2018	357900	MEAL REIMBRSMNT	APR-17-18	5/8/2018	MAI
909	8224	KYLE L SKOGMAN	Meal Allowances	28.00	4/30/2018	357166	MEAL REIMBRSMNT	APR-2-18	4/10/2018	SUBTRAN
910	8379	JOSEPH M LODERMEIER	Meal Allowances	10.00	4/30/2018	357947	MEAL REIMBRSMNT	MAY-6-18	5/10/2018	MAI
911	2749	KEVIN LEE JOHNSON	Meal Allowances	10.00	5/31/2018	358174	MEAL REIMBRSMNT	MAY-13-18	5/22/2018	MAI
912	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	5/31/2018	358422	MEAL REIMBRSMNT	MAY-19-18	5/29/2018	MAI
913	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	5/31/2018	358546	MEAL REIMBRSMNT	MAY-26-18	6/5/2018	MAI
914	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	5/31/2018	358546	MEAL REIMBRSMNT	MAY-28-18	6/5/2018	MAI
915	2769	GEORGE D SCHMAUS	Meal Allowances	28.00	5/31/2018	358197	MEAL REIMBRSMNT	MAY-11-18	5/22/2018	MAI
916	2769	GEORGE D SCHMAUS	Meal Allowances	28.00	5/31/2018	358421	MEAL REIMBRSMNT	MAY-19-18	5/29/2018	MAI
917	2769	GEORGE D SCHMAUS	Meal Allowances	279.00	5/31/2018	358545	MEAL REIMBRSMNT	MAY-30-18	6/5/2018	MAI
918	2781	KYLE M SHAY	Meal Allowances	28.00	5/31/2018	358315	MEAL REIMBRSMNT	MAY-18-2018	5/24/2018	TRA
919	2786	STEVEN W COLE	Meal Allowances	28.00	5/31/2018	3055	MEAL REIMBRSMNT	MAY-17-18	5/23/2018	MAI
920	2789	DEAN C JABLONSKI	Meal Allowances	137.00	5/31/2018	358172	MEAL REIMBRSMNT	MAY-16-18	5/22/2018	MAI
921	2790	SHANE KLOTZ	Meal Allowances	28.00	5/31/2018	358403	MEAL REIMBRSMNT	MAY-19-18	5/29/2018	MAI
922	2793	DANIEL W NICKLAY	Meal Allowances	190.00	5/31/2018	358411	MEAL REIMBRSMNT	MAY-23-18	5/29/2018	MAI
923	2815	MARK R MATTHEES	Meal Allowances	10.00	5/31/2018	358408	MEAL REIMBRSMNT	MAY-25-18	5/29/2018	MAI
924	4024	SHARON R TEDROW	Meal Allowances	28.00	5/31/2018	358551	MEAL REIMBRSMNT	MAY-29-18	6/5/2018	CUS
925	4424	JOSH RAYMOND	Meal Allowances	251.00	5/31/2018	358190	MEAL REIMBRSMNT	MAY-9-18	5/22/2018	MAI
926	4905	JACOB MAJESKI	Meal Allowances	10.00	5/31/2018	358537	MEAL REIMBRSMNT	MAY-25-18	6/5/2018	MAI
927	6412	GREG S NELSON	Meal Allowances	109.00	5/31/2018	358184	MEAL REIMBRSMNT	MAY-16-18	5/22/2018	MAI
928	6701	BRANDON LUNDE	Meal Allowances	279.00	5/31/2018	358536	MEAL REIMBRSMNT	MAY-30-18	6/5/2018	MAI
929	6796	SHEILA FLODIN	Meal Allowances	28.00	5/31/2018	357678	MEAL REIMBRSMNT	APR-30-18	5/3/2018	CUS
930	6796	SHEILA FLODIN	Meal Allowances	28.00	5/31/2018	357996	MEAL REIMBURSEMENT	MAY-10-18	5/15/2018	CUS
931	6796	SHEILA FLODIN	Meal Allowances	28.00	5/31/2018	358283	MEAL REIMBRSMNT	MAY-21-18	5/24/2018	CUS
932	7024	KYLE A SCHAFER	Meal Allowances	28.00	5/31/2018	358196	MEAL REIMBRSMNT	MAY-11-18	5/22/2018	MAI
933	7817	KENT P HOHBACH	Meal Allowances	28.00	5/31/2018	358165	MEAL REIMBRSMNT	MAY-17-18	5/22/2018	MAI
934	7974	KYLE J R RYMAN	Meal Allowances	213.00	5/31/2018	358194	MEAL REIMBRSMNT	MAY-9-18	5/22/2018	MAI
935	8095	SHANE J THOMPSON	Meal Allowances	38.00	5/31/2018	358199	MEAL REIMBRSMNT	MAY-4-18	5/22/2018	MAI
936	8095	SHANE J THOMPSON	Meal Allowances	10.00	5/31/2018	358552	MEAL REIMBRSMNT	MAY-25-18	6/5/2018	MAI
937	8096	PATRICK M EMOND	Meal Allowances	28.00	5/31/2018	358159	MEAL REIMBRSMNT	MAY-17-18	5/22/2018	MAI
938	8096	PATRICK M EMOND	Meal Allowances	109.00	5/31/2018	358394	MEAL REIMBRSMNT	MAY-20-18	5/29/2018	MAI
939	8097	LUCAS M WAXON	Meal Allowances	56.00	5/31/2018	358202	MEAL REIMBRSMNT	APR-20-18	5/22/2018	MAI
940	8098	JORDAN L SAUNDERS	Meal Allowances	112.00	5/31/2018	358420	MEAL REIMBRSMNT	MAY-23-18	5/29/2018	MAI
941	8224	KYLE L SKOGMAN	Meal Allowances	28.00	5/31/2018	358009	MEAL REIMBRSMNT	MAY-7-18	5/15/2018	OILSPILL
942	8261	BRANDON KARNICK	Meal Allowances	28.00	5/31/2018	358003	MEAL REIMBRSMNT	MAY-7-18	5/15/2018	OILSPILL
943	8499	ALEXANDER MCCUTCHEON	Meal Allowances	28.00	5/31/2018	358409	MEAL REIMBRSMNT	MAY-19-18	5/29/2018	MAI
944	8639	CLAY R FLECK	Meal Allowances	28.00	5/31/2018	358162	MEAL REIMBRSMNT	MAY-16-18	5/22/2018	MAI
945	8727	WYATT JENSEN	Meal Allowances	10.00	5/31/2018	358173	MEAL REIMBRSMNT	MAY-13-18	5/22/2018	MAI
946	2765	MARK J BOEGEMAN	Meal Allowances	127.00	6/30/2018	358761	MEAL REMBRSMNT	JUNE-12-18	6/19/2018	MAI
947	2769	GEORGE D SCHMAUS	Meal Allowances	58.00	6/30/2018	358930	MEAL REIMBRSMNT	JUNE-19-18	6/26/2018	MAI
948	2786	STEVEN W COLE	Meal Allowances	43.00	6/30/2018	3086	MEAL REMBRSMNT	JUNE-9-18	6/20/2018	MAI
949	2786	STEVEN W COLE	Meal Allowances	238.00	6/30/2018	3091	MEAL REIMBRSMNT	JUNE-21-18	6/27/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
950	2793	DANIEL W NICKLAY	Meal Allowances	15.00	6/30/2018	358658	MEAL REIMBRSMNT	JUNE-2-18	6/12/2018	MAI
951	2809	PAUL G KEHRER	Meal Allowances	180.00	6/30/2018	358784	MEAL REMBRSMNT	JUNE-10-18	6/19/2018	MAI
952	2828	RANDY A DEGROOT	Meal Allowances	28.00	6/30/2018	359329	MEAL REIMBRSMNT	JUNE-22-18	7/10/2018	MLT
953	2941	ERIC C GEHRKE	Meal Allowances	25.00	6/30/2018	358893	MEAL REIMBRSMNT	JUNE-16-18	6/26/2018	MAI
954	2941	ERIC C GEHRKE	Meal Allowances	20.00	6/30/2018	358893	MEAL REIMBRSMNT	JUNE-18-18	6/26/2018	MAI
955	4905	JACOB MAJESKI	Meal Allowances	185.00	6/30/2018	359164	EXPENSE REPORT	JUNE-28-18	7/3/2018	MAI
956	6129	COLE C MCWATERS	Meal Allowances	155.00	6/30/2018	358787	MEAL REMBRSMNT	JUNE-5-18	6/19/2018	MAI
957	6321	CASEY P O'BRIEN	Meal Allowances	124.00	6/30/2018	358791	MEAL REMBRSMNT	JUNE-12-18	6/19/2018	MAI
958	6418	KURT BECHEL	Meal Allowances	43.00	6/30/2018	3085	MEAL REMBRSMNT	JUNE-9-18	6/20/2018	MAI
959	6796	SHEILA FLODIN	Meal Allowances	28.00	6/30/2018	359123	MEAL REIMBRSMNT	JUNE-26-18	6/28/2018	CUS
960	7024	KYLE A SCHAFER	Meal Allowances	210.00	6/30/2018	358929	MEAL REIMBRSMNT	JUNE-21-18	6/26/2018	MAI
961	7056	TIMOTHY D VANDERLINDE	Meal Allowances	28.00	6/30/2018	359176	EXPENSE REPORT	JUNE-17-18	7/3/2018	MAI
962	7817	KENT P HOHBACH	Meal Allowances	28.00	6/30/2018	358898	MEAL REIMBRSMNT	JUNE-18-18	6/26/2018	MAI
963	8095	SHANE J THOMPSON	Meal Allowances	195.00	6/30/2018	359172	EXPENSE REPORT	JUNE-28-18	7/3/2018	MAI
964	8096	PATRICK M EMOND	Meal Allowances	20.00	6/30/2018	358889	MEAL REIMBRSMNT	JUNE-18-18	6/26/2018	MAI
965	8096	PATRICK M EMOND	Meal Allowances	28.00	6/30/2018	359120	MEAL REIMBRSMNT	JUNE-22-18	6/28/2018	MAI
966	8097	LUCAS M WAXON	Meal Allowances	20.00	6/30/2018	358946	MEAL REIMBRSMNT	JUNE-18-18	6/26/2018	MAI
967	8379	JOSEPH M LODERMEIER	Meal Allowances	25.00	6/30/2018	358910	MEAL REIMBRSMNT	JUNE-16-18	6/26/2018	MAI
968	8379	JOSEPH M LODERMEIER	Meal Allowances	10.00	6/30/2018	359163	EXPENSE REPORT	JUNE-25-18	7/3/2018	MAI
969	8722	STEPHEN BARBER	Meal Allowances	28.00	6/30/2018	358637	MEAL REIMBRSMNT	APR-18-18	6/12/2018	COLLCTEXP
970	8722	STEPHEN BARBER	Meal Allowances	28.00	6/30/2018	358637	MEAL REIMBRSMNT	JUNE-6-18	6/12/2018	COLLCTEXP
971	8727	WYATT JENSEN	Meal Allowances	28.00	6/30/2018	358906	MEAL REIMBRSMNT	JUNE-19-18	6/26/2018	MAI
972	2765	MARK J BOEGEMAN	Meal Allowances	28.00	7/31/2018	360176	MEAL REIMBRSMNT	JUL-28-18	8/7/2018	MAI
973	2769	GEORGE D SCHMAUS	Meal Allowances	43.00	7/31/2018	359639	MEAL REIMBRSMNT	JULY-4-18	7/17/2018	MAI
974	2787	JEFFREY W EWANIKA	Meal Allowances	66.00	7/31/2018	359605	MEAL REIMBRSMNT	JULY-9-18	7/17/2018	MAI
975	2789	DEAN C JABLONSKI	Meal Allowances	56.00	7/31/2018	359614	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
976	2789	DEAN C JABLONSKI	Meal Allowances	28.00	7/31/2018	359614	MEAL REIMBRSMNT	JULY-11-18	7/17/2018	MAI
977	2789	DEAN C JABLONSKI	Meal Allowances	10.00	7/31/2018	359614	MEAL REIMBRSMNT	JULY-13-18	7/17/2018	MAI
978	2789	DEAN C JABLONSKI	Meal Allowances	28.00	7/31/2018	360202	MEAL REIMBRSMNT	JUL-26-18	8/7/2018	MAI
979	2796	ANDREW F SCHRUPP	Meal Allowances	180.00	7/31/2018	3118	MEAL REIMBRSMNT	JULY-4-18	7/18/2018	MAI
980	2815	MARK R MATTHEES	Meal Allowances	10.00	7/31/2018	359622	MEAL REIMBRSMNT	JUNE-27-18	7/17/2018	MAI
981	2815	MARK R MATTHEES	Meal Allowances	43.00	7/31/2018	359622	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
982	2815	MARK R MATTHEES	Meal Allowances	10.00	7/31/2018	359622	MEAL REIMBRSMNT	JULY-13-18	7/17/2018	MAI
983	2941	ERIC C GEHRKE	Meal Allowances	127.00	7/31/2018	360195	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
984	2946	JAY R BAUER	Meal Allowances	129.00	7/31/2018	3124	MEAL REIMBRSMNT	JULY-18-18	7/27/2018	MAI
985	2956	JANET M ZIMMER	Meal Allowances	28.00	7/31/2018	360069	MEAL REIMBRSMNT	JULY-26-18	7/31/2018	UGTRAN
986	4024	SHARON R TEDROW	Meal Allowances	28.00	7/31/2018	359642	MEAL REIMBRSMNT	JULY-3-18	7/17/2018	CUS
987	5171	NICHOLAS M VOUGHT	Meal Allowances	218.00	7/31/2018	359647	MEAL REIMBRSMNT	JULY-4-18	7/17/2018	MAI
988	6129	COLE C MCWATERS	Meal Allowances	28.00	7/31/2018	359624	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
989	6321	CASEY P O'BRIEN	Meal Allowances	10.00	7/31/2018	359627	MEAL REIMBRSMNT	JULY-13-18	7/17/2018	MAI
990	6412	GREG S NELSON	Meal Allowances	43.00	7/31/2018	359626	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
991	6412	GREG S NELSON	Meal Allowances	91.00	7/31/2018	359943	MEAL REIMBRSMNT	JULY-15-18	7/26/2018	MAI
992	6418	KURT BECHEL	Meal Allowances	28.00	7/31/2018	3146	MEAL REIMBRSMNT	JUL-25-18	8/8/2018	MAI
993	7170	LORI J OLSON	Meal Allowances	28.00	7/31/2018	359890	MEAL REMBRSMNT	JULY-16-18	7/24/2018	CUS
994	7332	MCKENNON M VANDERVEEN	Meal Allowances	28.00	7/31/2018	359343	MEAL REIMBRSMT	JUL-3-18	7/10/2018	GENMT
995	7332	MCKENNON M VANDERVEEN	Meal Allowances	28.00	7/31/2018	360065	MEAL REIMBRSMNT	JULY-26-18	7/31/2018	UGTRAN
996	7817	KENT P HOHBACH	Meal Allowances	28.00	7/31/2018	360198	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
997	7974	KYLE J R RYMAN	Meal Allowances	10.00	7/31/2018	359636	MEAL REIMBRSMNT	JULY-13-18	7/17/2018	MAI
998	8095	SHANE J THOMPSON	Meal Allowances	10.00	7/31/2018	359644	MEAL REIMBRSMNT	JULY-13-18	7/17/2018	MAI
999	8096	PATRICK M EMOND	Meal Allowances	66.00	7/31/2018	359604	MEAL REIMBRSMNT	JULY-9-18	7/17/2018	MAI
1,000	8097	LUCAS M WAXON	Meal Allowances	43.00	7/31/2018	359949	MEAL REIMBRSMNT	JULY-4-18	7/26/2018	MAI
1,001	8098	JORDAN L SAUNDERS	Meal Allowances	10.00	7/31/2018	359638	MEAL REIMBRSMNT	JUNE-27-18	7/17/2018	MAI
1,002	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	7/31/2018	359638	MEAL REIMBRSMNT	JULY-12-18	7/17/2018	MAI
1,003	8098	JORDAN L SAUNDERS	Meal Allowances	66.00	7/31/2018	359947	MEAL REIMBRSMNT	JULY-18-18	7/26/2018	MAI
1,004	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	7/31/2018	360218	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
1,005	8379	JOSEPH M LODERMEIER	Meal Allowances	94.00	7/31/2018	360207	MEAL REIMBRSMNT	JUL-31-18	8/7/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1,006	8424	TRAVIS J FREESE	Meal Allowances	10.00	7/31/2018	359928	MEAL REIMBRSMNT	JULY-13-18	7/26/2018	MAI
1,007	8424	TRAVIS J FREESE	Meal Allowances	127.00	7/31/2018	360191	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
1,008	8424	TRAVIS J FREESE	Meal Allowances	28.00	7/31/2018	360191	MEAL REIMBRSMNT	JUL-28-18	8/7/2018	MAI
1,009	8499	ALEXANDER MCCUTCHEON	Meal Allowances	56.00	7/31/2018	359623	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
1,010	8727	WYATT JENSEN	Meal Allowances	28.00	7/31/2018	359615	MEAL REIMBRSMNT	JULY-1-18	7/17/2018	MAI
1,011	8838	REID D WHEELER	Meal Allowances	28.00	7/31/2018	359649	MEAL REIMBRSMNT	JUNE-29-18	7/17/2018	MAI
1,012	8850	CHRISTIAN M ANDERSON	Meal Allowances	28.00	7/31/2018	360173	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
1,013	8851	JACOB M MORTENSON	Meal Allowances	28.00	7/31/2018	360209	MEAL REIMBRSMNT	JUL-25-18	8/7/2018	MAI
1,014	2727	JACKIE A BAUER	Meal Allowances	43.00	8/31/2018	360484	MEAL REIMBRSMNT	AUG-9-18	8/16/2018	FAIRSHOW
1,015	2739	JULIE A SIMONSEN	Meal Allowances	28.00	8/31/2018	360259	EXPENSE REPORT	AUG/2018	8/9/2018	FAIRSHOW
1,016	2753	STACY E TEPFER	Meal Allowances	28.00	8/31/2018	360933	MEAL REIMBRSMNT	AUG-26-18	8/30/2018	MAT
1,017	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	8/31/2018	360219	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,018	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	8/31/2018	360593	MEAL REIMBRSMNT	AUG-14-18	8/21/2018	MAI
1,019	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	8/31/2018	360885	MEAL REMBRSMNT	AUG-21-18	8/28/2018	MAI
1,020	2765	MARK J BOEGEMAN	Meal Allowances	10.00	8/31/2018	360544	MEAL REIMBRSMNT	AUG-8-18	8/21/2018	MAI
1,021	2765	MARK J BOEGEMAN	Meal Allowances	28.00	8/31/2018	360544	MEAL REIMBRSMNT	AUG-9-18	8/21/2018	MAI
1,022	2765	MARK J BOEGEMAN	Meal Allowances	28.00	8/31/2018	360544	MEAL REIMBRSMNT	AUG-14-18	8/21/2018	MAI
1,023	2765	MARK J BOEGEMAN	Meal Allowances	28.00	8/31/2018	361126	MEAL REIMBURSEMENT	AUG-27-18	9/11/2018	MAI
1,024	2765	MARK J BOEGEMAN	Meal Allowances	28.00	8/31/2018	361126	MEAL REIMBURSEMENT	AUG-30-18	9/11/2018	MAI
1,025	2767	JANE E SIEBENALER	Meal Allowances	15.00	8/31/2018	360424	EXPENSE REPORT	AUG/2018	8/14/2018	FAIRSHOW
1,026	2769	GEORGE D SCHMAUS	Meal Allowances	56.00	8/31/2018	361172	MEAL REIMBURSEMENT 8/26-8/27	AUG-27-18	9/11/2018	MAI
1,027	2769	GEORGE D SCHMAUS	Meal Allowances	56.00	8/31/2018	361172	MEAL REIMBURSEMENTS 8/30-8/3	AUG-31-18	9/11/2018	MAI
1,028	2789	DEAN C JABLONSKI	Meal Allowances	28.00	8/31/2018	360202	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,029	2789	DEAN C JABLONSKI	Meal Allowances	183.00	8/31/2018	361147	MEAL REIMBURSEMENT 8/16-8/23	AUG-23-18	9/11/2018	MAI
1,030	2790	SHANE KLOTZ	Meal Allowances	63.00	8/31/2018	360575	MEAL REIMBRSMNT	AUG-5-18	8/21/2018	MAI
1,031	2793	DANIEL W NICKLAY	Meal Allowances	221.00	8/31/2018	361163	MEAL REIMBURSEMENTS 8/23-8/2	AUG-29-18	9/11/2018	MAI
1,032	2809	PAUL G KEHRER	Meal Allowances	28.00	8/31/2018	360204	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,033	2809	PAUL G KEHRER	Meal Allowances	28.00	8/31/2018	361150	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,034	2815	MARK R MATTHEES	Meal Allowances	94.00	8/31/2018	360580	MEAL REIMBRSMNT	JUL-31-18	8/21/2018	MAI
1,035	2815	MARK R MATTHEES	Meal Allowances	28.00	8/31/2018	361159	MEAL REIMBURSEMENT	AUG-27-18	9/11/2018	MAI
1,036	2828	RANDY A DEGROOT	Meal Allowances	15.00	8/31/2018	360384	MEAL REIMBURSMNT	AUG-7-18	8/14/2018	FAIRSHOW
1,037	2908	DAVID S REINKE	Meal Allowances	56.00	8/31/2018	360589	EXPENSE REPORT	AUG/2018	8/21/2018	FAIRSHOW
1,038	2941	ERIC C GEHRKE	Meal Allowances	28.00	8/31/2018	361142	MEAL REIMBURSEMENT	AUG-27-18	9/11/2018	MAI
1,039	2946	JAY R BAUER	Meal Allowances	28.00	8/31/2018	3185	MEAL REIMBURSEMENT	JUL-1-18	9/12/2018	MAI
1,040	3213	KIMBERLY A HELLESON	Meal Allowances	28.00	8/31/2018	360569	MEAL REIMBRSMNT	AUG-8-18	8/21/2018	FAIRSHOW
1,041	4024	SHARON R TEDROW	Meal Allowances	15.00	8/31/2018	360595	MEAL REIMBRSMNT	AUG-11-18	8/21/2018	FAIRSHOW
1,042	4159	STEPHANIE RISTOW	Meal Allowances	28.00	8/31/2018	360215	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	CUS
1,043	4237	CHERYL R KLOTZ	Meal Allowances	71.00	8/31/2018	360574	MEAL REIMBRSMNT	AUG-10-18	8/21/2018	FAIRSHOW
1,044	4424	JOSH RAYMOND	Meal Allowances	221.00	8/31/2018	360588	MEAL REIMBRSMNT	AUG-15-18	8/21/2018	MAI
1,045	4905	JACOB MAJESKI	Meal Allowances	28.00	8/31/2018	361156	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,046	5171	NICHOLAS M VOUGHT	Meal Allowances	28.00	8/31/2018	361179	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,047	6129	COLE C MCWATERS	Meal Allowances	28.00	8/31/2018	360581	MEAL REIMBRSMNT	AUG-14-18	8/21/2018	MAI
1,048	6129	COLE C MCWATERS	Meal Allowances	155.00	8/31/2018	361160	MEAL REIMBURSEMENT 8/16-8/26	AUG-26-18	9/11/2018	MAI
1,049	6129	COLE C MCWATERS	Meal Allowances	28.00	8/31/2018	361160	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,050	6412	GREG S NELSON	Meal Allowances	28.00	8/31/2018	360210	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,051	6412	GREG S NELSON	Meal Allowances	28.00	8/31/2018	361162	MEAL REIMBURSEMENT	AUG-27-18	9/11/2018	MAI
1,052	6701	BRANDON LUNDE	Meal Allowances	28.00	8/31/2018	361155	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,053	6701	BRANDON LUNDE	Meal Allowances	56.00	8/31/2018	361155	MEAL REIMBURSEMENT 8/30-8/31	AUG-31-18	9/11/2018	MAI
1,054	6796	SHEILA FLODIN	Meal Allowances	28.00	8/31/2018	360190	MEAL REIMBRSMNT	AUG-2-18	8/7/2018	CUS
1,055	7056	TIMOTHY D VANDERLINDE	Meal Allowances	28.00	8/31/2018	361177	MEAL REIMBURSEMENT	AUG-26-18	9/11/2018	MAI
1,056	7285	MIKE PLUTOWSKI	Meal Allowances	43.00	8/31/2018	360521	EXPENSE REPORT	AUG/2018	8/16/2018	FAIRSHOW
1,057	7724	MARA J GRECO	Meal Allowances	28.00	8/31/2018	360666	MEAL REIMBRSMNT	AUG-16-18	8/23/2018	CUS
1,058	7724	MARA J GRECO	Meal Allowances	28.00	8/31/2018	360910	MEAL REIMBRSMNT	AUG-27-18	8/30/2018	CUS
1,059	7818	JADDE MALSZYCKI	Meal Allowances	10.00	8/31/2018	360870	MEAL REMBRSMNT	JULY-13-18	8/28/2018	MAI
1,060	7974	KYLE J R RYMAN	Meal Allowances	221.00	8/31/2018	360591	MEAL REIMBRSMNT	AUG-15-18	8/21/2018	MAI
1,061	8095	SHANE J THOMPSON	Meal Allowances	28.00	8/31/2018	360597	MEAL REIMBRSMNT	AUG-10-18	8/21/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1,062	8095	SHANE J THOMPSON	Meal Allowances	38.00	8/31/2018	360891	MEAL REMBRSMNT	AUG-22-18	8/28/2018	MAI
1,063	8096	PATRICK M EMOND	Meal Allowances	28.00	8/31/2018	360185	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,064	8096	PATRICK M EMOND	Meal Allowances	10.00	8/31/2018	360565	MEAL REIMBRSMNT	AUG-8-18	8/21/2018	MAI
1,065	8096	PATRICK M EMOND	Meal Allowances	28.00	8/31/2018	361134	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,066	8097	LUCAS M WAXON	Meal Allowances	76.00	8/31/2018	360600	MEAL REIMBRSMNT	AUG-5-18	8/21/2018	MAI
1,067	8097	LUCAS M WAXON	Meal Allowances	221.00	8/31/2018	361180	MEAL REIMBURSEMENTS 8/23-8/29	AUG-29-18	9/11/2018	MAI
1,068	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	8/31/2018	361170	MEAL REIMBURSEMENT	AUG-28-18	9/11/2018	MAI
1,069	8379	JOSEPH M LODERMEIER	Meal Allowances	56.00	8/31/2018	361154	MEAL REIMBURSEMENT 8/28-8/30	AUG-30-18	9/11/2018	MAI
1,070	8632	WYATT J GADIENT	Meal Allowances	28.00	8/31/2018	361141	MEAL REIMBURSEMENT	JUL-1-18	9/11/2018	MAI
1,071	8632	WYATT J GADIENT	Meal Allowances	28.00	8/31/2018	361141	MEAL REIMBURSEMENT	AUG-13-18	9/11/2018	MAI
1,072	8632	WYATT J GADIENT	Meal Allowances	10.00	8/31/2018	361141	MEAL REIMBURSEMENT	AUG-13-18	9/11/2018	MAI
1,073	8632	WYATT J GADIENT	Meal Allowances	28.00	8/31/2018	360567	MEAL REIMBRSMNT	AUG-14-18	8/21/2018	MAI
1,074	8639	CLAY R FLECK	Meal Allowances	28.00	8/31/2018	361138	MEAL REIMBURSEMENT	JUL-1-18	9/11/2018	MAI
1,075	8639	CLAY R FLECK	Meal Allowances	28.00	8/31/2018	361138	MEAL REIMBURSEMENT	JUL-28-18	9/11/2018	MAI
1,076	8650	STEPHANIE M PEDERSON	Meal Allowances	58.00	8/31/2018	360882	MEAL REMBRSMNT	AUG-12-18	8/28/2018	FAIRSHOW
1,077	8727	WYATT JENSEN	Meal Allowances	15.00	8/31/2018	361148	MEAL REIMBURSEMENT	AUG-25-18	9/11/2018	MAI
1,078	8742	MASON J DEGROOT	Meal Allowances	28.00	8/31/2018	360183	MEAL REIMBRSMNT	AUG-1-18	8/7/2018	MAI
1,079	8838	REID D WHEELER	Meal Allowances	28.00	8/31/2018	360602	MEAL REIMBRSMNT	AUG-11-18	8/21/2018	MAI
1,080	8838	REID D WHEELER	Meal Allowances	15.00	8/31/2018	361181	MEAL REIMBURSEMENT	AUG-25-18	9/11/2018	MAI
1,081	8838	REID D WHEELER	Meal Allowances	28.00	8/31/2018	361181	MEAL REIMBURSEMENT	AUG-26-18	9/11/2018	MAI
1,082	2749	KEVIN LEE JOHNSON	Meal Allowances	28.00	9/30/2018	361828	MEAL REIMBRSMNT	SEP-14-18	10/4/2018	MAI
1,083	2749	KEVIN LEE JOHNSON	Meal Allowances	28.00	9/30/2018	361828	MEAL REIMBRSMNT	SEP-17-18	10/4/2018	MAI
1,084	2749	KEVIN LEE JOHNSON	Meal Allowances	25.00	9/30/2018	361828	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,085	2749	KEVIN LEE JOHNSON	Meal Allowances	10.00	9/30/2018	361828	MEAL REIMBRSMNT	SEP-24-18	10/4/2018	MAI
1,086	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	9/30/2018	361841	MEAL REIMBRSMNT	SEP-17-18	10/4/2018	MAI
1,087	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	9/30/2018	361841	MEAL REIMBRSMNT	SEP-28-18	10/4/2018	MAI
1,088	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	9/30/2018	361841	MEAL REIMBRSMNT	SEP-29-18	10/4/2018	MAI
1,089	2765	MARK J BOEGEMAN	Meal Allowances	106.00	9/30/2018	361580	MEAL REIMBRSMNT	SEP-10-18	9/27/2018	MAI
1,090	2765	MARK J BOEGEMAN	Meal Allowances	28.00	9/30/2018	361580	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,091	2765	MARK J BOEGEMAN	Meal Allowances	28.00	9/30/2018	361580	MEAL REIMBRSMNT	SEP-20-18	9/27/2018	MAI
1,092	2765	MARK J BOEGEMAN	Meal Allowances	28.00	9/30/2018	361580	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,093	2769	GEORGE D SCHMAUS	Meal Allowances	162.00	9/30/2018	361172	MEAL REIMBURSEMENTS 9/1-9/5/1	SEP-5-18	9/11/2018	MAI
1,094	2769	GEORGE D SCHMAUS	Meal Allowances	28.00	9/30/2018	361635	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,095	2769	GEORGE D SCHMAUS	Meal Allowances	25.00	9/30/2018	361635	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,096	2786	STEVEN W COLE	Meal Allowances	10.00	9/30/2018	3198	MEAL REIMBRSMNT	SEP-10-18	9/28/2018	MAI
1,097	2786	STEVEN W COLE	Meal Allowances	28.00	9/30/2018	3198	MEAL REIMBRSMNT	SEP-14-18	9/28/2018	MAI
1,098	2786	STEVEN W COLE	Meal Allowances	10.00	9/30/2018	3198	MEAL REIMBRSMNT	SEP-18-18	9/28/2018	MAI
1,099	2786	STEVEN W COLE	Meal Allowances	185.00	9/30/2018	3221	MEAL REIMBRSMNT	SEP-26-18	10/10/2018	MAI
1,100	2787	JEFFREY W EWANIKA	Meal Allowances	28.00	9/30/2018	361594	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,101	2789	DEAN C JABLONSKI	Meal Allowances	28.00	9/30/2018	361147	MEAL REIMBURSEMENT	SEP-5-18	9/11/2018	MAI
1,102	2790	SHANE KLOTZ	Meal Allowances	28.00	9/30/2018	361611	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,103	2790	SHANE KLOTZ	Meal Allowances	25.00	9/30/2018	361829	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,104	2790	SHANE KLOTZ	Meal Allowances	28.00	9/30/2018	361829	MEAL REIMBRSMNT	SEP-28-18	10/4/2018	MAI
1,105	2793	DANIEL W NICKLAY	Meal Allowances	28.00	9/30/2018	361835	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,106	2809	PAUL G KEHRER	Meal Allowances	28.00	9/30/2018	361610	MEAL REIMBRSMNT	SEP-13-18	9/27/2018	MAI
1,107	2809	PAUL G KEHRER	Meal Allowances	28.00	9/30/2018	361610	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,108	2809	PAUL G KEHRER	Meal Allowances	10.00	9/30/2018	361610	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,109	2809	PAUL G KEHRER	Meal Allowances	10.00	9/30/2018	361914	MEAL REIMBRSMNT	SEP-25-18	10/9/2018	MAI
1,110	2815	MARK R MATTHEES	Meal Allowances	28.00	9/30/2018	361159	MEAL REIMBURSEMENT	SEP-4-18	9/11/2018	MAI
1,111	2815	MARK R MATTHEES	Meal Allowances	73.00	9/30/2018	361618	MEAL REIMBRSMNT	SEP-22-18	9/27/2018	MAI
1,112	2831	GARY C SCHAFFER	Meal Allowances	28.00	9/30/2018	361357	MEAL REIMBRSMNT	SEP-11-18	9/18/2018	MLT
1,113	2941	ERIC C GEHRKE	Meal Allowances	28.00	9/30/2018	361598	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,114	2941	ERIC C GEHRKE	Meal Allowances	10.00	9/30/2018	361598	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,115	2946	JAY R BAUER	Meal Allowances	28.00	9/30/2018	3197	MEAL REIMBRSMNT	SEP-14-18	9/28/2018	MAI
1,116	2946	JAY R BAUER	Meal Allowances	28.00	9/30/2018	3197	MEAL REIMBRSMNT	SEP-17-18	9/28/2018	MAI
1,117	2946	JAY R BAUER	Meal Allowances	25.00	9/30/2018	3197	MEAL REIMBRSMNT	SEP-21-18	9/28/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1,118	4424	JOSH RAYMOND	Meal Allowances	28.00	9/30/2018	361632	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,119	4424	JOSH RAYMOND	Meal Allowances	10.00	9/30/2018	361632	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,120	4695	ANNE M RAYMOND	Meal Allowances	28.00	9/30/2018	361168	MEAL REIMBURSEMENT	SEP-4-18	9/11/2018	CASH
1,121	4905	JACOB MAJESKI	Meal Allowances	28.00	9/30/2018	361617	MEAL REIMBRSMNT	SEP-17-18	9/27/2018	MAI
1,122	4905	JACOB MAJESKI	Meal Allowances	25.00	9/30/2018	361617	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,123	5171	NICHOLAS M VOUGHT	Meal Allowances	190.00	9/30/2018	361639	MEAL REIMBRSMNT	SEP-21-18	9/27/2018	MAI
1,124	5209	BLOHM, DARYL B	Meal Allowances	28.00	9/30/2018	361947	MEAL REIMBRSMNT	SEP-20-18	10/11/2018	SUBCOM
1,125	6129	COLE C MCWATERS	Meal Allowances	28.00	9/30/2018	361763	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,126	6129	COLE C MCWATERS	Meal Allowances	25.00	9/30/2018	361763	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,127	6321	CASEY P O'BRIEN	Meal Allowances	28.00	9/30/2018	361769	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,128	6321	CASEY P O'BRIEN	Meal Allowances	185.00	9/30/2018	361922	MEAL REIMBRSMNT	SEP-26-18	10/9/2018	MAI
1,129	6412	GREG S NELSON	Meal Allowances	10.00	9/30/2018	361767	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,130	6418	KURT BECHEL	Meal Allowances	28.00	9/30/2018	3203	MEAL REIMBRSMNT	SEP-17-18	10/3/2018	MAI
1,131	6418	KURT BECHEL	Meal Allowances	28.00	9/30/2018	3203	MEAL REIMBRSMNT	SEP-20-18	10/3/2018	MAI
1,132	6418	KURT BECHEL	Meal Allowances	114.00	9/30/2018	3220	MEAL REIMBRSMNT	SEP-30-18	10/10/2018	MAI
1,133	6701	BRANDON LUNDE	Meal Allowances	124.00	9/30/2018	361155	MEAL REIMBURSEMENT 9/1-9/4	SEP-4-18	9/11/2018	USO
1,134	6701	BRANDON LUNDE	Meal Allowances	28.00	9/30/2018	361760	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,135	6701	BRANDON LUNDE	Meal Allowances	10.00	9/30/2018	361760	MEAL REIMBRSMNT	SEP-18-18	10/2/2018	MAI
1,136	6701	BRANDON LUNDE	Meal Allowances	10.00	9/30/2018	361760	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,137	6796	SHEILA FLODIN	Meal Allowances	28.00	9/30/2018	361340	MEAL REIMBRSMNT	SEP-12-18	9/18/2018	CUS
1,138	7024	KYLE A SCHAFER	Meal Allowances	190.00	9/30/2018	361927	MEAL REIMBRSMNT	SEP-22-18	10/9/2018	MAI
1,139	7056	TIMOTHY D VANDERLINDE	Meal Allowances	28.00	9/30/2018	361842	MEAL REIMBRSMNT	SEP-17-18	10/4/2018	MAI
1,140	7056	TIMOTHY D VANDERLINDE	Meal Allowances	25.00	9/30/2018	361842	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,141	7817	KENT P HOHBACH	Meal Allowances	28.00	9/30/2018	361822	MEAL REIMBRSMNT	SEP-14-18	10/4/2018	MAI
1,142	7817	KENT P HOHBACH	Meal Allowances	28.00	9/30/2018	361822	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,143	7818	JADDE MALSZYCKI	Meal Allowances	28.00	9/30/2018	361833	MEAL REIMBRSMNT	SEP-17-18	10/4/2018	MAI
1,144	7818	JADDE MALSZYCKI	Meal Allowances	28.00	9/30/2018	361833	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,145	7960	GARETT M DOFFING	Meal Allowances	28.00	9/30/2018	361196	MEAL REIMBRSMNT	SEP-2-18	9/13/2018	SUBRELAY
1,146	7960	GARETT M DOFFING	Meal Allowances	28.00	9/30/2018	361426	MEAL REIMBRSMNT	SEP-13-18	9/20/2018	SUBRELAY
1,147	7974	KYLE J R RYMAN	Meal Allowances	28.00	9/30/2018	361778	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,148	7974	KYLE J R RYMAN	Meal Allowances	28.00	9/30/2018	361778	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,149	8095	SHANE J THOMPSON	Meal Allowances	28.00	9/30/2018	361785	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,150	8095	SHANE J THOMPSON	Meal Allowances	25.00	9/30/2018	361785	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,151	8096	PATRICK M EMOND	Meal Allowances	28.00	9/30/2018	361134	MEAL REIMBURSEMENT	SEP-5-18	9/11/2018	MAI
1,152	8096	PATRICK M EMOND	Meal Allowances	28.00	9/30/2018	361744	MEAL REIMBRSMNT	SEP-14-18	10/2/2018	MAI
1,153	8096	PATRICK M EMOND	Meal Allowances	28.00	9/30/2018	361744	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,154	8096	PATRICK M EMOND	Meal Allowances	10.00	9/30/2018	361744	MEAL REIMBRSMNT	SEP-19-18	10/2/2018	MAI
1,155	8096	PATRICK M EMOND	Meal Allowances	25.00	9/30/2018	361744	MEAL REIMBRSMNT	SEP-20-18	10/2/2018	MAI
1,156	8098	JORDAN L SAUNDERS	Meal Allowances	116.00	9/30/2018	361839	MEAL REIMBRSMNT	SEP-13-18	10/4/2018	MAI
1,157	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	9/30/2018	361779	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,158	8098	JORDAN L SAUNDERS	Meal Allowances	10.00	9/30/2018	361839	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,159	8379	JOSEPH M LODERMEIER	Meal Allowances	28.00	9/30/2018	361759	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,160	8379	JOSEPH M LODERMEIER	Meal Allowances	20.00	9/30/2018	361759	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,161	8379	JOSEPH M LODERMEIER	Meal Allowances	10.00	9/30/2018	361917	MEAL REIMBRSMNT	SEP-25-18	10/9/2018	MAI
1,162	8424	TRAVIS J FREESE	Meal Allowances	28.00	9/30/2018	361139	MEAL REIMBURSEMENT	SEP-4-18	9/11/2018	MAI
1,163	8424	TRAVIS J FREESE	Meal Allowances	28.00	9/30/2018	361747	MEAL REIMBRSMNT	SEP-13-18	10/2/2018	MAI
1,164	8424	TRAVIS J FREESE	Meal Allowances	28.00	9/30/2018	361747	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,165	8424	TRAVIS J FREESE	Meal Allowances	28.00	9/30/2018	361816	MEAL REIMBRSMNT	SEP-21-18	10/4/2018	MAI
1,166	8499	ALEXANDER MCCUTCHEON	Meal Allowances	28.00	9/30/2018	361762	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,167	8499	ALEXANDER MCCUTCHEON	Meal Allowances	25.00	9/30/2018	361762	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,168	8632	WYATT J GADIENT	Meal Allowances	28.00	9/30/2018	361748	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,169	8727	WYATT JENSEN	Meal Allowances	28.00	9/30/2018	361755	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,170	8727	WYATT JENSEN	Meal Allowances	25.00	9/30/2018	361755	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,171	8838	REID D WHEELER	Meal Allowances	28.00	9/30/2018	361791	MEAL REIMBRSMNT	SEP-17-18	10/2/2018	MAI
1,172	8838	REID D WHEELER	Meal Allowances	25.00	9/30/2018	361791	MEAL REIMBRSMNT	SEP-21-18	10/2/2018	MAI
1,173	2749	KEVIN LEE JOHNSON	Meal Allowances	10.00	10/31/2018	361913	MEAL REIMBRSMNT	OCT-3-18	10/9/2018	MAI

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1,174	2749	KEVIN LEE JOHNSON	Meal Allowances	10.00	10/31/2018	362664	MEAL REIMBRSMNT	OCT-4-18	11/1/2018	MAI
1,175	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	10/31/2018	362557	MEAL REIMBRSMNT	OCT-18-18	10/30/2018	MAI
1,176	2765	MARK J BOEGEMAN	Meal Allowances	10.00	10/31/2018	361898	MEAL REIMBRSMNT	OCT-4-18	10/9/2018	MAI
1,177	2765	MARK J BOEGEMAN	Meal Allowances	28.00	10/31/2018	362638	MEAL REIMBRSMNT	OCT-29-18	11/1/2018	MAI
1,178	2769	GEORGE D SCHMAUS	Meal Allowances	56.00	10/31/2018	362556	MEAL REIMBRSMNT	OCT-18-18	10/30/2018	MAI
1,179	2769	GEORGE D SCHMAUS	Meal Allowances	15.00	10/31/2018	362556	MEAL REIMBRSMNT	OCT-20-18	10/30/2018	MAI
1,180	2786	STEVEN W COLE	Meal Allowances	28.00	10/31/2018	3237	MEAL REIMBRSMNT	OCT-5-18	10/31/2018	MAI
1,181	2787	JEFFREY W EWANIKA	Meal Allowances	239.00	10/31/2018	362522	MEAL REIMBRSMNT	OCT-18-18	10/30/2018	MAI
1,182	2789	DEAN C JABLONSKI	Meal Allowances	165.00	10/31/2018	362536	MEAL REIMBRSMNT	OCT-10-18	10/30/2018	MAI
1,183	2793	DANIEL W NICKLAY	Meal Allowances	10.00	10/31/2018	361835	MEAL REIMBRSMNT	OCT-3-18	10/4/2018	MAI
1,184	2815	MARK R MATTHEES	Meal Allowances	175.00	10/31/2018	362540	MEAL REIMBRSMNT	OCT-24-18	10/30/2018	MAI
1,185	4905	JACOB MAJESKI	Meal Allowances	200.00	10/31/2018	362539	MEAL REIMBRSMNT	OCT-4-18	10/30/2018	MAI
1,186	5171	NICHOLAS M VOUGHT	Meal Allowances	239.00	10/31/2018	362566	MEAL REIMBRSMNT	OCT-18-18	10/30/2018	MAI
1,187	5209	BLOHM, DARYL B	Meal Allowances	28.00	10/31/2018	361947	MEAL REIMBRSMNT	OCT-3-18	10/11/2018	SUBCOM
1,188	6412	GREG S NELSON	Meal Allowances	165.00	10/31/2018	362546	MEAL REIMBRSMNT	OCT-10-18	10/30/2018	MAI
1,189	6418	KURT BECHEL	Meal Allowances	94.00	10/31/2018	3220	MEAL REIMBRSMNT	OCT-4-18	10/10/2018	MAI
1,190	6796	SHEILA FLODIN	Meal Allowances	28.00	10/31/2018	362524	MEAL REIMBRSMNT	OCT-25-18	10/30/2018	CUS
1,191	7817	KENT P HOHBACH	Meal Allowances	28.00	10/31/2018	362529	MEAL REIMBRSMNT	OCT-5-18	10/30/2018	MAI
1,192	7817	KENT P HOHBACH	Meal Allowances	28.00	10/31/2018	362529	MEAL REIMBRSMNT	OCT-12-18	10/30/2018	MAI
1,193	7974	KYLE J R RYMAN	Meal Allowances	10.00	10/31/2018	362672	MEAL REIMBRSMNT	OCT-26-18	11/1/2018	MAI
1,194	7986	MITCHELL J OLSON	Meal Allowances	56.00	10/31/2018	362482	MEAL REIMBRSMNT	OCT-10-18	10/25/2018	COLLCTEXP
1,195	8095	SHANE J THOMPSON	Meal Allowances	137.00	10/31/2018	362563	MEAL REIMBRSMNT	OCT-20-18	10/30/2018	MAI
1,196	8096	PATRICK M EMOND	Meal Allowances	10.00	10/31/2018	362649	MEAL REIMBRSMNT	OCT-26-18	11/1/2018	MAI
1,197	8097	LUCAS M WAXON	Meal Allowances	28.00	10/31/2018	362679	MEAL REIMBRSMNT	OCT-29-18	11/1/2018	MAI
1,198	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	10/31/2018	362555	MEAL REIMBRSMNT	OCT-12-18	10/30/2018	MAI
1,199	8098	JORDAN L SAUNDERS	Meal Allowances	137.00	10/31/2018	362673	MEAL REIMBRSMNT	OCT-24-18	11/1/2018	MAI
1,200	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	10/31/2018	362673	MEAL REIMBRSMNT	OCT-29-18	11/1/2018	MAI
1,201	8379	JOSEPH M LODERMEIER	Meal Allowances	20.00	10/31/2018	362538	MEAL REIMBRSMNT	OCT-3-18	10/30/2018	MAI
1,202	8424	TRAVIS J FREESE	Meal Allowances	10.00	10/31/2018	361903	MEAL REIMBRSMNT	OCT-4-18	10/9/2018	MAI
1,203	8489	ADAM L MULDER	Meal Allowances	56.00	10/31/2018	362140	MEAL REIMBURSMNT	OCT-10-18	10/16/2018	COLLCTEXP
1,204	8632	WYATT J GADIENT	Meal Allowances	28.00	10/31/2018	362655	MEAL REIMBRSMNT	SEP-21-18	11/1/2018	MAI
1,205	8639	CLAY R FLECK	Meal Allowances	28.00	10/31/2018	362654	MEAL REIMBRSMNT	SEP-17-18	11/1/2018	MAI
1,206	8639	CLAY R FLECK	Meal Allowances	25.00	10/31/2018	362654	MEAL REIMBRSMNT	SEP-21-18	11/1/2018	MAI
1,207	8639	CLAY R FLECK	Meal Allowances	28.00	10/31/2018	362654	MEAL REIMBRSMNT	SEP-29-18	11/1/2018	MAI
1,208	8719	SCOTT B WERNER	Meal Allowances	28.00	10/31/2018	362499	MEAL REIMBRSMNT	OCT-16-18	10/25/2018	COLLCTEXP
1,209	8838	REID D WHEELER	Meal Allowances	10.00	10/31/2018	362569	MEAL REIMBRSMNT	OCT-4-18	10/30/2018	MAI
1,210	2765	MARK J BOEGEMAN	Meal Allowances	28.00	11/30/2018	363925	MEAL REIMBRSMNT	NOV-27-18	12/11/2018	MAI
1,211	2769	GEORGE D SCHMAUS	Meal Allowances	109.00	11/30/2018	363592	MEAL REIMBRSMNT	NOV-19-18	11/29/2018	MAI
1,212	2786	STEVEN W COLE	Meal Allowances	10.00	11/30/2018	3267	MEAL REIMBRSMNT	NOV-17-18	11/30/2018	MAI
1,213	2789	DEAN C JABLONSKI	Meal Allowances	170.00	11/30/2018	363946	MEAL REIMBRSMNT	NOV-28-18	12/11/2018	MAI
1,214	2790	SHANE KLOTZ	Meal Allowances	86.00	11/30/2018	363577	MEAL REIMBRSMNT	NOV-13-18	11/29/2018	MAI
1,215	2941	ERIC C GEHRKE	Meal Allowances	132.00	11/30/2018	363565	MEAL REIMBRSMNT	OCT-31-18	11/29/2018	MAI
1,216	4159	STEPHANIE RISTOW	Meal Allowances	28.00	11/30/2018	362766	MEAL REIMBRSMNT	NOV-1-18	11/6/2018	CUS
1,217	4159	STEPHANIE RISTOW	Meal Allowances	28.00	11/30/2018	363079	MEAL RIMBRSMNT	NOV-5-18	11/8/2018	CUS
1,218	4159	STEPHANIE RISTOW	Meal Allowances	28.00	11/30/2018	363587	MEAL REIMBRSMNT	NOV-20-18	11/29/2018	CUS
1,219	4159	STEPHANIE RISTOW	Meal Allowances	28.00	11/30/2018	363587	MEAL REIMBRSMNT	NOV-26-18	11/29/2018	CUS
1,220	4424	JOSH RAYMOND	Meal Allowances	175.00	11/30/2018	363585	MEAL REIMBRSMNT	NOV-7-18	11/29/2018	MAI
1,221	6412	GREG S NELSON	Meal Allowances	43.00	11/30/2018	363953	MEAL REIMBRSMNT	NOV-19-18	12/11/2018	MAI
1,222	7024	KYLE A SCHAFER	Meal Allowances	38.00	11/30/2018	363964	MEAL REIMBRSMNT	NOV-17-18	12/11/2018	MAI
1,223	7974	KYLE J R RYMAN	Meal Allowances	28.00	11/30/2018	363963	MEAL REIMBRSMNT	NOV-27-18	12/11/2018	MAI
1,224	8095	SHANE J THOMPSON	Meal Allowances	203.00	11/30/2018	363596	MEAL REIMBRSMNT	NOV-5-18	11/29/2018	MAI
1,225	8096	PATRICK M EMOND	Meal Allowances	170.00	11/30/2018	363936	MEAL REIMBRSMNT	NOV-28-18	12/11/2018	MAI
1,226	8379	JOSEPH M LODERMEIER	Meal Allowances	114.00	11/30/2018	363951	MEAL REIMBRSMNT	NOV-15-18	12/11/2018	MAI
1,227	8424	TRAVIS J FREESE	Meal Allowances	94.00	11/30/2018	363563	MEAL REIMBRSMNT	NOV-7-18	11/29/2018	MAI
1,228	8595	NICHOLAS E WAXON	Meal Allowances	28.00	11/30/2018	363601	MEAL REIMBRSMNT	NOV-26-18	11/29/2018	COLLCTEXP
1,229	8719	SCOTT B WERNER	Meal Allowances	28.00	11/30/2018	363228	MEAL REIMBRSMNT	NOV-9-18	11/15/2018	COLLCTEXP

Meal Expenses

Line	Vendor #	Vendor	Account Type	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Check Date	Project
1,230	8719	SCOTT B WERNER	Meal Allowances	28.00	11/30/2018	363602	MEAL REIMBRSMNT	NOV-21-18	11/29/2018	COLLCTEXP
1,231	2757	MARTY L SCHUHWERCK	Meal Allowances	28.00	12/31/2018	363965	MEAL REIMBRSMNT	DEC-1-18	12/11/2018	MAI
1,232	2757	MARTY L SCHUHWERCK	Meal Allowances	15.00	12/31/2018	364334	MEAL REMBRSMNT	DEC-15-18	12/20/2018	MAI
1,233	2765	MARK J BOEGEMAN	Meal Allowances	71.00	12/31/2018	364779	MEAL REIMBURSMNT	DEC-18-18	1/15/2019	MAI
1,234	2793	DANIEL W NICKLAY	Meal Allowances	137.00	12/31/2018	364322	MEAL REMBRSMNT	DEC-3-18	12/20/2018	MAI
1,235	2809	PAUL G KEHRER	Meal Allowances	28.00	12/31/2018	364797	MEAL REIMBURSMNT	DEC-20-18	1/15/2019	MAI
1,236	4833	JASON L HUSTAD	Meal Allowances	28.00	12/31/2018	3328	MEAL REIMBURSMNT	DEC-19-18	1/16/2019	STA
1,237	5171	NICHOLAS M VOUGHT	Meal Allowances	112.00	12/31/2018	364818	MEAL REIMBURSMNT	DEC-26-18	1/15/2019	MAI
1,238	6412	GREG S NELSON	Meal Allowances	28.00	12/31/2018	363953	MEAL REIMBRSMNT	DEC-1-18	12/11/2018	MAI
1,239	6418	KURT BECHEL	Meal Allowances	43.00	12/31/2018	3298	MEAL REMBRSMNT	DEC-16-18	12/21/2018	MAI
1,240	7974	KYLE J R RYMAN	Meal Allowances	137.00	12/31/2018	363963	MEAL REIMBRSMNT	DEC-3-18	12/11/2018	MAI
1,241	8098	JORDAN L SAUNDERS	Meal Allowances	28.00	12/31/2018	364816	MEAL REIMBURSMNT	DEC-13-18	1/15/2019	MAI
1,242	8639	CLAY R FLECK	Meal Allowances	28.00	12/31/2018	363939	MEAL REIMBRSMNT	DEC-1-18	12/11/2018	MAI

Total Company - Meal Allowances	**$ 22,620.00**
Total Company Meal Expenses	**$ 91,145.52**
Total AGI2018 Meal Expenses	***$ 1,539.93***
Total Company Meal Expense w/o AGI	**$ 89,605.59**

Workpaper 15C
Dues & Membership Expenses

Account 83610 - Dues & Memberships

Line	Vendor #	Vendor	Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
1	875	APPLE VALLEY CHAMBER OF COMM	952.00	1/31/2018	353634	2018 DUES-P JOHNSON	21230	11/14/2017	COMMREL
2	689	BURNSVILLE CHAMBER OF COMMERCE	1,345.00	1/31/2018	354854	2018-MEMBERSHIP	42768	12/28/2017	COMMREL
3	5411	BURNSVILLE ROTARY FOUNDATION	400.00	1/31/2018	355488	J SHELDON 1/1-6/30/18	1111801	1/18/2018	SHELDON
4	3984	CANNON FALLS AREA C OF C	450.00	1/31/2018	355805	MEMBERSHIP 2018	895	2/1/2018	COMMREL
5	918	DAKOTA CTY REGIONAL C OF C	1,700.00	1/31/2018	354861	2018 DUES	67742	12/28/2017	COMMREL
6	3201	EDAM	495.00	1/31/2018	354954	M LOFTHUS/P JOHNSON	2018-MEMBERSHIP	1/4/2018	ECO
7	3239	ENVIRONMENTAL INITIATIVE	600.00	1/31/2018	354004	2018 CORP MEMBERSHIP	2018-MEMBERSHIP	11/28/2017	ENVIRON
8	8303	GREATER MSP	10,000.00	1/31/2018	356058	2018 ANNUAL INVESTMENT	2016	2/13/2018	ECO
9	2938	HENKE, CARLA S (NSAC)	200.00	1/31/2018	2897	EXPENSE REPORT	JAN/2018-EX	1/19/2018	FIN
10	3105	IRWA	271.00	1/31/2018	354013	T SCHMITZ 2018 DUES	438147	11/28/2017	EDU
11	3105	IRWA	286.00	1/31/2018	354013	C KNUDSEN 2018 DUES	430398	11/28/2017	EDU
12	2767	JANE E SIEBENALER (Assn of Energy Engineers)	215.00	1/31/2018	354341	EXPENSE REPORT	DEC-5-17	12/7/2017	ACS
13	7871	LAKE BYLLESBY IMPROVEMENT ASSN	50.00	1/31/2018	355104	DUES 2018	2018-MEMBERSHIP	1/9/2018	ECO
14	5196	LAKEVILLE AREA ARTS CENTER	100.00	1/31/2018	355320	MEMBERSHIP DUES	2018-MEMBERSHIP	1/16/2018	ACS
15	653	LAKEVILLE AREA CHAMBER OF COMM	855.00	1/31/2018	354887	2018 MEMBERSHIP	29158	12/28/2017	COMMREL
16	5120	LAKEVILLE AREA HISTORICAL SOC	50.00	1/31/2018	354138	2018 CORP MEMBERSHIP	2018-MEMBERSHIP	11/30/2017	ACS
17	4002	MAEDC	125.00	1/31/2018	353886	M LOFTHUS 2018 MEMBERSHIP	01305	11/21/2017	ECO
18	8333	METROPOLITAN UTILITY COORD COM	1,000.00	1/31/2018	356227	2018 MEMBERHSIP DUES	2018DEA	2/20/2018	SAF
19	4272	MIDWEST LAWSON USER GROUP	250.00	1/31/2018	354889	C HENKE MEMBERSHIP	2018-DUES	12/28/2017	LAWSON
20	695	MINNESOTA SAFETY COUNCIL	545.00	1/31/2018	354438	2018 MEMBERSHIP	001289 2018	12/12/2017	SAF
21	4005	MINNESOTA SHERIFFS' ASSN	25.00	1/31/2018	355671	MEMBERSHIP DUES	2018-19822	1/25/2018	ACS
22	7273	MN ASSN OF CHURCH FACILITY MGR	300.00	1/31/2018	354686	2018 DUES	1733	12/21/2017	DSM
23	7157	MN DEED	625.00	1/31/2018	354025	M LOFTHUS 2018 MBRSHP	105134929	11/28/2017	ECO
24	337	MN RURAL ELECTRIC ASSOCIATION	13,699.88	1/31/2018	355670	TOUCHSTONE DUES 2018	INV00012953	1/25/2018	BRANDING
25	337	MN RURAL ELECTRIC ASSOCIATION	76,004.99	1/31/2018	355670	1ST HALF GENL & EDU DUES	INV00012986	1/25/2018	AMS
26	275	NRECA NATIONAL	110.00	1/31/2018	355928	LOSS CTRL PROF FEES 2018	2007321	2/6/2018	SAF
27	275	NRECA NATIONAL	175.00	1/31/2018	355928	CCC PROF FEES 2018/J MILLER	2016165	2/6/2018	PUBREL
28	4049	NREDA	275.00	1/31/2018	354143	P JOHNSON 2018 MEMBERSHIP	2018-10245	11/30/2017	ECO
29	4049	NREDA	275.00	1/31/2018	354143	M LOFTHUS 2018 MEMBERSHIP	2018-13976	11/30/2017	ECO
30	3100	REMA	1,800.00	1/31/2018	355118	2018 DUES	REMA INV02940	1/9/2018	AMS
31	3888	RIVER HEIGHTS CHAMBER	1,233.75	1/31/2018	354147	2018 MEMBERSHIP/P JOHNSON	8357	11/30/2017	COMMREL
32	4282	ROTARY CLUB OF FARMINGTON	175.00	1/31/2018	355783	JAN-MAR 2018 DUES/L LANDWEHR	1/2018-DUES	1/30/2018	MKT
33	6718	TIM DOHERTY (Assn of Energy Engineers)	215.00	1/31/2018	354417	EXPENSE REPORT	DEC-5-17	12/12/2017	KEY
34	3226	US BANK (IEEE)	201.00	1/31/2018	2009451	CC Recap-Glenda L. Hewitt	9/2017-GLH	9/29/2017	EDU
35	3226	US BANK (IEEE)	236.00	1/31/2018	2009457	CC Recap-Betty Jo Kiesow	10/2017-BJK	10/31/2017	NCD
36	3226	US BANK (IEEE)	291.00	1/31/2018	2009461	CC Recap-Jeffrey L Schoenecker	11/2017-JLS	11/29/2017	ETS
37	3226	US BANK (IEEE)	291.00	1/31/2018	2009461	CC Recap-Craig C Turner	11/2017-CCT	11/29/2017	EDU
38	3226	US BANK (Assn of Energy Engineers)	300.00	1/31/2018	2009471	CC Recap-Timothy J. Doherty	1/2018-TJD	1/30/2018	KEY
39	8668	ELKO NEW MARKET CHAMBER	200.00	2/28/2018	356657	DUES 5/31/17-6/1/18	2017-DUES	3/13/2018	ACS
40	3207	MN DEPT OF PUBLIC SAFETY	25.00	2/28/2018	356514	HAZ CHEM INVENTORY FEE	1904000182017 M-93710	3/6/2018	HAZARD
41	6302	PRSA	330.00	2/28/2018	354984	J MILLER 2/1/18-1/31/19	2/2018-1366787	1/4/2018	PUBREL
42	4219	RECYCLING ASSOCIATION OF MN	200.00	2/28/2018	356396	12 MO BUS MBRSHIP	4606	2/27/2018	ENVIRON
43	4546	ROTARY CLUB OF APPLE VALLEY	62.50	2/28/2018	356300	G MILLER 1/1-3/31/18	1546	2/22/2018	AMS
44	5474	TOUCHSTONE ENERGY COOPERATIVES	35,000.00	2/28/2018	356308	2018 DUES	2032473	2/22/2018	BRANDING
45	4261	US CHAMBER OF COMMERCE	500.00	2/28/2018	354995	P JOHNSON 2/1/18-1/31/19	2/2018-727482	1/4/2018	COMMREL
46	2938	HENKE, CARLA S (MN Soc of CPAs)	300.00	3/31/2018	2975	EXPENSE REPORT	MAR/2018	3/21/2018	FIN
47	3168	MN POLLUTION CONTROL AGENCY	330.48	3/31/2018	357201	HAZARDOUS WASTE FEES	10000046708	4/12/2018	HAZARD
48	2564	SAM'S CLUB	41.25	3/31/2018	357253	MEMBERSHIP	3/2018-4731	4/17/2018	HRP
49	2564	SAM'S CLUB	41.25	3/31/2018	357253	MEMBERSHIP	3/2018-4731	4/17/2018	AEN
50	2564	SAM'S CLUB	41.25	3/31/2018	357253	MEMBERSHIP	3/2018-4731	4/17/2018	ACS
51	2564	SAM'S CLUB	41.25	3/31/2018	357253	MEMBERSHIP	3/2018-4731	4/17/2018	HRP
52	3226	US BANK (Assn of Energy Engineers)	195.00	3/31/2018	2009481	CC Recap-Tyler W. Kashdan	3/2018-TWK	3/29/2018	DSM
53	676	HASTINGS AREA CHAMBER OF COMM	825.00	4/30/2018	357297	PJOHNSON MBRSHP 4/1/18-3/31/1	5840	4/19/2018	COMMREL
54	4139	NATIONAL FIRE PROTECTION ASN	175.00	4/30/2018	357161	V FRANDRUP 4/01/18-3/31/19	7154096X	4/10/2018	BLD

Account 83610 - Dues & Memberships

Line	Vendor #	Vendor	Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
55	4282	ROTARY CLUB OF FARMINGTON	175.00	4/30/2018	357371	4TH QTR/APR-JUN18-LLANDWEHR	1129	4/24/2018	MKT
56	3226	US BANK (Dakota County)	579.10	4/30/2018	2009486	CC Recap-Bernard M. Kolnberger	4/2018-BMK	4/30/2018	HAZARD
57	2908	DAVID S REINKE (Assn of Energy Engineers)	215.00	5/31/2018	358191	EXPENSE REPORT	MAY/2018	5/22/2018	DSM
58	3226	US BANK (MSPE)	384.00	5/31/2018	2009490	CC Recap-Craig C. Turner	5/2018-CCT	5/31/2018	ETS
59	3199	AMERICAN PAYROLL ASSOCIATION	219.00	6/30/2018	357627	2018 APA RENEW/160557	6/2018-160557	5/1/2018	PAY
60	4060	MINNESOTA CHAMBER OF COMMERCE	2,455.00	6/30/2018	358304	MEMBERSHIP 6/1/18-5/31/19	000005760	5/24/2018	COMMREL
61	8358	AFCOM	299.00	7/31/2018	358106	7/2018-2019 MEMBR-M LOFTHUS	5560	5/17/2018	ECO
62	5411	BURNSVILLE ROTARY FOUNDATION	350.00	7/31/2018	360423	J SHELDON 7/1-12/31/18	180730	8/14/2018	SHELDON
63	5615	IEDC	185.00	7/31/2018	358126	P JOHNSON 7/1/18-6/30/19	7/2018-212618	5/17/2018	COMMREL
64	7599	MN GEOTHERMAL HEAT PUMP ASSN	250.00	7/31/2018	359302	D REINKE 7/1/18-6/30/19	2018/2019-DR	7/5/2018	DSM
65	337	MN RURAL ELECTRIC ASSOCIATION	76,004.99	7/31/2018	360103	2ND HALF GENL & EDU DUES	INV00013474	8/2/2018	AMS
66	4282	ROTARY CLUB OF FARMINGTON	175.00	7/31/2018	359635	L LANDWEHR JUL-SEP DUES	1155	7/17/2018	MKT
67	2564	SAM'S CLUB	(30.00)	7/31/2018	360527	MEMBERSHIP	7/2018-4731	8/16/2018	HRP
68	2564	SAM'S CLUB	(20.25)	7/31/2018	360527	MEMBERSHIP	7/2018-4731	8/16/2018	ACS
69	2564	SAM'S CLUB	(20.24)	7/31/2018	360527	MEMBERSHIP	7/2018-4731	8/16/2018	HRP
70	2564	SAM'S CLUB	(20.24)	7/31/2018	360527	MEMBERSHIP	7/2018-4731	8/16/2018	AEN
71	2564	SAM'S CLUB	9.75	7/31/2018	360527	MEMBERSHIP	7/2018-4731	8/16/2018	PUR
72	3341	SHRM	209.00	7/31/2018	358548	M MEHRHOFF 7/1/18-6/30/19	9007469909	6/5/2018	HRP
73	3226	US BANK (AELSLAGID)	122.50	7/31/2018	2009496	CC Recap-Craig C. Turner	6/2018-CCT	7/2/2018	ETS
74	3226	US BANK (AELSLAGID)	122.50	7/31/2018	2009496	CC Recap-Jeffrey L. Schoenecker	6/2018-JLS	7/2/2018	ETS
75	5615	IEDC	420.00	8/30/2018	358167	M LOFTHUS 8/1/18-7/31/19	8/2018-144104	5/22/2018	ECO
76	275	NRECA NATIONAL	80,579.00	8/31/2018	360212	2018 MEMBERSHIP DUES	2145462	8/7/2018	AMS
77	3226	US BANK (SHRM)	209.00	8/31/2018	2009507	CC Recap-Christene D. Dodge-Ra	8/2018-CDD	8/30/2018	HRP
78	4827	DANIEL P ROSS (Assn of Energy Engineers)	195.00	9/30/2018	361459	EXPENSE REPORT	SEP/2018	9/20/2018	KEY
79	8855	GREAT PLAINS INSTATUTE	2,500.00	9/30/2018	361046	DUES 9/2018-8/2019	2018-MEMBERSHIP	9/6/2018	ELECCAR
80	3226	US BANK (IEEE)	235.00	9/30/2018	2009512	CC Recap-Patrick M Hughes	9/2018-PMH	10/1/2018	ETS
81	2938	HENKE, CARLA S (MN State Bd pf Acctncy)	26.50	10/31/2018	3250	EXPENSE REPORT	OCT/2018	11/2/2018	FIN
82	8203	MRA-THE MANAGEMENT ASSOCIATION	1,500.00	10/31/2018	361061	M MEHRHOFF 10/1/18-10/1/19	9109023	9/6/2018	HRP
83	3226	US BANK (NFPA)	175.00	10/31/2018	2009520	CC Recap-Patrick M Hughes	10/2018-PMH	10/31/2018	ETS
84	3226	US BANK (NSPE)	299.00	10/31/2018	2009520	CC Recap-Jeffrey L Schoenecker	10/2018-JLS	10/31/2018	AUO
85	4042	CRAIG TURNER IEEE)	294.00	11/30/2018	363477	EXPENSE REPORT	NOV/2018	11/27/2018	AMS
86	3239	ENVIRONMENTAL INITIATIVE	600.00	11/30/2018	363558	MEMBERSHIP 11/1/18-10/31/19	17235	11/29/2018	ENVIRON
87	4160	REPAC	25.00	11/30/2018	355119	MEMBERSHIP RENEWALS	2018-MEMBERSHIP	1/9/2018	BOD
88	4546	ROTARY CLUB OF APPLE VALLEY	62.50	11/30/2018	363681	G MILLER 4/1/18-6/30/18	1601	12/4/2018	AMS
89	4546	ROTARY CLUB OF APPLE VALLEY	62.50	11/30/2018	363681	G MILLER 7/1/18-9/30/18	1671	12/4/2018	AMS
90	4546	ROTARY CLUB OF APPLE VALLEY	62.50	11/30/2018	363681	G MILLER 10/1/18-12/31/18	1716	12/4/2018	AMS
91	4282	ROTARY CLUB OF FARMINGTON	175.00	11/30/2018	363184	L LANDWEHR 2ND QTR 2018-2019	1196	11/13/2018	MKT
92	3226	US BANK (Survey Monkey)	360.00	11/30/2018	2009526	CC Recap-Christene D. Dodge-Ra	11/2018-CDD	11/30/2018	HRP
93	7341	CANNON FALLS AREA HISTORICAL	100.00	12/31/2018	364278	MEMBERSHIP 12/2018-11/2019	12/2018-MEMBERSHIP	12/20/2018	ACS
94	2767	JANE E SIEBENALER (Assn of Energy Engineers)	215.00	12/31/2018	364187	EXPENSE REPORT	DEC/2018	12/18/2018	ACS
95	2767	JANE E SIEBENALER (Certified Energy Mgr.)	300.00	12/31/2018	364408	EXPENSE REPORT	DEC/2018.2	12/27/2018	ACS
96	653	LAKEVILLE AREA CHAMBER OF COMM	855.00	12/31/2018	364598	2019 MEMEBERSHIP	30735	1/8/2019	COMMREL
97	4282	ROTARY CLUB OF FARMINGTON	175.00	12/31/2018	364609	L LANDWEHR 3RD QTR 2018-2019	1222	1/8/2019	MKT
98	3226	US BANK (Dept of Agriculture)	25.56	12/31/2018	2009534	CC Recap-Bernard M. Kolnberger	12/2018-BMK	12/31/2018	USO

Total Company - Dues & Memberships **$ 325,544.27**

Workpaper 15D
Community Events Expenses

Account 84560 - Community Events

Line	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Project
1	653	LAKEVILLE AREA CHAMBER OF COMM	400.00	1/31/2018	354673	CURLING TRNMNT-P JOHNSON	29349	COMMREL
2	676	HASTINGS AREA CHAMBER OF COMM	75.00	1/31/2018	355173	AWARDS DINNER/KIMMES 1/25	5701	COMMREL
3	653	LAKEVILLE AREA CHAMBER OF COMM	52.50	1/31/2018	355321	2018 ANNUAL MTG	29483	COMMREL
4	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	DEYOE
5	653	LAKEVILLE AREA CHAMBER OF COMM	52.50	1/31/2018	355321	2018 ANNUAL MTG	29483	LEKSON
6	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	PITTMAN
7	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	SCHREINER
8	689	BURNSVILLE CHAMBER OF COMMERCE	15.00	1/31/2018	355451	1/16/18 NETWORK/P JOHNSON	42882	COMMREL
9	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	1/31/2018	2009471	CC Recap-Julie A. Simonsen	1/2018-JAS	COMMREL
10	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	1/31/2018	2009471	CC Recap-Margaret (Peggy) P. J	1/2018-PPJ	COMMREL
11	3226	US BANK-FRESH ENERGY	35.00	1/31/2018	2009471	CC Recap-Cherry A. Jordan	1/2018-CAJ	DEYOE
12	676	HASTINGS AREA CHAMBER OF COMM	15.00	2/28/2018	355569	STATE OF THE CITY 2/1/18	5741	COMMREL
13	676	HASTINGS AREA CHAMBER OF COMM	15.00	2/28/2018	355569	STATE OF THE CITY 2/1/18	5741	COMMREL
14	676	HASTINGS AREA CHAMBER OF COMM	15.00	2/28/2018	355569	STATE OF THE CITY 2/1/18	5741	ECO
15	676	HASTINGS AREA CHAMBER OF COMM	15.00	2/28/2018	355569	STATE OF THE CITY 2/1/18	5741	KIMMES
16	4060	MINNESOTA CHAMBER OF COMMERCE	150.00	2/28/2018	355774	SESSION PRIORITIES 2/20/18	SP18-012018-0040	COMMREL
17	4060	MINNESOTA CHAMBER OF COMMERCE	150.00	2/28/2018	355774	SESSION PRIORITIES 2/20/18	SP18-012018-0040	LEKSON
18	653	LAKEVILLE AREA CHAMBER OF COMM	25.00	2/28/2018	356065	P JOHNSON/SUDS 2/8	29604	COMMREL
19	918	DAKOTA CTY REGIONAL C OF C	150.00	2/28/2018	356092	M LOFTHUS/SNS PRIOR 2/20	68102	COMMREL
20	918	DAKOTA CTY REGIONAL C OF C	150.00	2/28/2018	356092	M LOFTHUS/SNS PRIOR 2/20	68102	ECO
21	689	BURNSVILLE CHAMBER OF COMMERCE	130.00	2/28/2018	356210	G MILLER/SESSN PRIORITIES 2/20	43007	COMMREL
22	689	BURNSVILLE CHAMBER OF COMMERCE	15.00	2/28/2018	356360	P JOHNSON/BRKFST 2/16	43050	COMMREL
23	3888	RIVER HEIGHTS CHAMBER	300.00	2/28/2018	356457	SESSN PR/J GULACK, D MOE	8655	COMMREL
24	689	BURNSVILLE CHAMBER OF COMMERCE	15.00	2/28/2018	356650	P JOHNSON BREAKFAST 3/14	43063	COMMREL
25	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	2/28/2018	2009471	CC Recap-Julie A. Simonsen	1/2018-JAS	ECO
26	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	AMS
27	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	2/28/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	COMMREL
28	3226	US BANK-RIVER HEIGHTS	50.00	2/28/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	COMMREL
29	3226	US BANK-BURNSVILLE CHAMBER	25.00	2/28/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	COMMREL
30	3226	US BANK-BURNSVILLE CHAMBER	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	DEYOE
31	3226	US BANK-BURNSVILLE CHAMBER	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	ECO
32	3226	US BANK-BURNSVILLE CHAMBER	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	PITTMAN
33	3226	US BANK-RIVER HEIGHTS	50.00	2/28/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	SCHREINER
34	653	LAKEVILLE AREA CHAMBER OF COMM	25.00	3/31/2018	356225	P JOHNSON/LUNCHEON 3/15	29710	COMMREL
35	689	BURNSVILLE CHAMBER OF COMMERCE	100.00	3/31/2018	356259	BITE OF BURNSVILLE	43016	COMMREL
36	689	BURNSVILLE CHAMBER OF COMMERCE	15.00	3/31/2018	356829	M LOFTHUS/BRKFST 3/14	43187	ECO
37	875	APPLE VALLEY CHAMBER OF COMM	20.00	3/31/2018	356931	MBR LUNCH 3/21/18	21706	AEN
38	875	APPLE VALLEY CHAMBER OF COMM	20.00	3/31/2018	356931	MBR LUNCH 3/21/18	21706	COMMREL
39	875	APPLE VALLEY CHAMBER OF COMM	20.00	3/31/2018	356931	MBR LUNCH 3/21/18	21706	ECO
40	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	3/31/2018	2009481	CC Recap-Julie A. Simonsen	3/2018-JAS	COMMREL
41	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	DANNER
42	3226	US BANK-ROSEMOUNT-IRISH FOR A DAY	99.12	3/31/2018	2009481	CC Recap-Julie A. Simonsen	3/2018-JAS	DEYOE
43	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	SCHREINER
44	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	VAN
45	653	LAKEVILLE AREA CHAMBER OF COMM	100.00	4/30/2018	357688	2/20 EVENT-DEYOE/PITTMAN	30124	DEYOE
46	653	LAKEVILLE AREA CHAMBER OF COMM	100.00	4/30/2018	357688	2/20 EVENT-DEYOE/PITTMAN	30124	PITTMAN
47	875	APPLE VALLEY CHAMBER OF COMM	100.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	AEN
48	875	APPLE VALLEY CHAMBER OF COMM	100.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	COMMREL
49	875	APPLE VALLEY CHAMBER OF COMM	600.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	COMMREL
50	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	DEYOE
51	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	PITTMAN
52	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	PTRAPP
53	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	SCHREINER

Account 84560 - Community Events

Line	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Project
54	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	VAN
55	689	BURNSVILLE CHAMBER OF COMMERCE	10.00	4/30/2018	357913	P JOHNSON/WOM EMP LUNCH	43198	COMMREL
56	337	MN RURAL ELECTRIC ASSOCIATION	1,000.00	4/30/2018	358182	SPONSOR& 2 GOLF TEAMS	INV00013339	COMMREL
57	3226	US BANK-BVL ROTARY-UNDER THE STREETLAMP	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	DEYOE
58	3226	US BANK-BVL ROTARY-UNDER THE STREETLAMP	118.72	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	LEKSON
59	3226	US BANK-BVL ROTARY-UNDER THE STREETLAMP	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	PITTMAN
60	3226	US BANK-BVL ROTARY-UNDER THE STREETLAMP	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	SCHREINER
61	3226	US BANK-BVL ROTARY-UNDER THE STREETLAMP	118.72	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	SHELDON
62	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	4/30/2018	2009486	CC Recap-Julie A. Simonsen	4/2018-JAS	COMMREL
63	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	4/30/2018	2009486	CC Recap-Julie A. Simonsen	4/2018-JAS	ECO
64	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	4/30/2018	2009486	CC Recap-Julie A. Simonsen	4/2018-JAS	ECO
65	918	DAKOTA CTY REGIONAL C OF C	25.00	5/31/2018	358274	M LOFTHUS/GOOD DAY 3/12/18	68305	ECO
66	875	APPLE VALLEY CHAMBER OF COMM	20.00	5/31/2018	358564	STATE OF THE CITY 5/23/18	21861	COMMREL
67	875	APPLE VALLEY CHAMBER OF COMM	20.00	5/31/2018	358564	STATE OF THE CITY 5/23/18	21861	COMMREL
68	875	APPLE VALLEY CHAMBER OF COMM	20.00	5/31/2018	358564	STATE OF THE CITY 5/23/18	21861	ECO
69	875	APPLE VALLEY CHAMBER OF COMM	20.00	5/31/2018	358564	STATE OF THE CITY 5/23/18	21861	PITTMAN
70	3226	US BANK-HARRYS CAFÉ	50.00	5/31/2018	2009490	CC Recap-Laverne G. Frandrup	5/2018-VGF	BLD
71	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	5/31/2018	2009490	CC Recap-Margaret (Peggy) P Jo	5/2018-PPJ	COMMREL
72	3226	US BANK-TASTE OF LAKEVILLE	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	DEYOE
73	3226	US BANK-TASTE OF LAKEVILLE	40.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	LEKSON
74	3226	US BANK-TASTE OF LAKEVILLE	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	PITTMAN
75	3226	US BANK-TASTE OF LAKEVILLE	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	SCHREINER
76	3226	US BANK-LAKEVILLE CHAMBER	165.00	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	VAN
77	3226	US BANK-LAKEVILLE CHAMBER	25.00	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	VAN
78	918	DAKOTA CTY REGIONAL C OF C	650.00	6/30/2018	356837	FOURSOME 6/18/18	2018-GOLFERS	ECO
79	689	BURNSVILLE CHAMBER OF COMMERCE	20.00	6/30/2018	358763	WOMEN EMPOWERED 5/15/18	43343	COMMREL
80	875	APPLE VALLEY CHAMBER OF COMM	160.00	6/30/2018	358811	GOLF SCRAMBLE	2018-GOLF	COMMREL
81	875	APPLE VALLEY CHAMBER OF COMM	160.00	6/30/2018	358811	GOLF SCRAMBLE	2018-GOLF	COMMREL
82	3984	CANNON FALLS AREA C OF C	9.00	6/30/2018	359111	P JOHNSON/BRKFST 6/21	1033	COMMREL
83	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	6/30/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	COMMREL
84	3226	US BANK-ECONOMIC DEV ASSOC	125.00	6/30/2018	2009490	CC Recap-Mark W. Lofthus	5/2018-MWL	ECO
85	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	6/30/2018	2009496	CC Recap-Cherry A. Jordan	6/2018-CAJ	AMS
86	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	6/30/2018	2009496	CC Recap-Julie A. Simonsen	6/2018-JAS	COMMREL
87	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	6/30/2018	2009496	CC Recap-Julie A. Simonsen	6/2018-JAS	COMMREL
88	3226	US BANK-MINNESOTA RURAL ELECTRIC	166.67	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	DEYOE
89	3226	US BANK-MINNESOTA RURAL ELECTRIC	166.66	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	HOLTON
90	3226	US BANK-MINNESOTA RURAL ELECTRIC	166.67	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	JONES
91	3886	FAIRVIEW FOUNDATION	100.00	8/31/2018	358457	SPONSORSHIP/CROQUET PLYR	18-03	COMMREL
92	8523	WINGS FINANCIAL FOUNDATION	600.00	8/31/2018	359913	SPONSORSHIP/GOLF	2018-GOLF	COMMREL
93	3886	FAIRVIEW FOUNDATION	800.00	8/31/2018	360187	4 GOLFERS 8/13/201	18-04	COMMREL
94	3226	US BANK-360 COMMUNITIES	125.00	8/31/2018	2009501	CC Recap-Brenda K. Kadlec	7/2018-BKK	COMMREL
95	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	8/31/2018	2009507	CC Recap-Julie A. Simonsen	8/2018-JAS	COMMREL
96	3226	US BANK-VOIGHTS BUS SERVICE-MN ECON DEV ACADEMY	150.00	8/31/2018	2009507	CC Recap-Mark W. Lofthus	8/2018-MWL	ECO
97	918	DAKOTA CTY REGIONAL C OF C	25.00	9/30/2018	361537	P JOHNSON 9/10/18	69062	COMMREL
98	875	APPLE VALLEY CHAMBER OF COMM	20.00	9/30/2018	361577	P JOHNSON CYBERCRIME LNCH 9/12	22118	COMMREL
99	689	BURNSVILLE CHAMBER OF COMMERCE	10.00	9/30/2018	361949	P JOHNSON 9/18/18 SOCIAL	43619	COMMREL
100	3226	US BANK-THE EAGAN FOUNDATION	110.00	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	BAKKEN
101	3226	US BANK-THE EAGAN FOUNDATION	110.00	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	BAKKEN
102	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	9/30/2018	2009512	CC Recap-Julie A Simonsen	9/2018-JAS	COMMREL
103	3226	US BANK-KIDS N KINSHIP	107.48	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	DEYOE
104	3226	US BANK-KIDS N KINSHIP	53.74	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	ECO
105	3226	US BANK-THE EAGAN FOUNDATION	55.00	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	ECO
106	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	9/30/2018	2009512	CC Recap-Julie A Simonsen	9/2018-JAS	ECO

Account 84560 - Community Events

Line	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Invoice	Project
107	3226	US BANK-KIDS N KINSHIP	53.74	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	LEKSON
108	3226	US BANK-KIDS N KINSHIP	53.74	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	LEKSON
109	3226	US BANK-KIDS N KINSHIP	107.48	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	SCHREINER
110	337	MN RURAL ELECTRIC ASSOCIATION	1,000.00	10/31/2018	358182	SPONSOR& 2 GOLF TEAMS	INV00013339	ACS
111	337	MN RURAL ELECTRIC ASSOCIATION	(1,000.00)	10/31/2018	358182	SPONSOR& 2 GOLF TEAMS	INV00013339	COMMREL
112	3226	US BANK-VOIGHTS BUS SERVICE-MN ECON DEV ACADEMY	671.39	10/31/2018	2009520	CC Recap-Mark W. Lofthus	10/2018-MWL	ECO
113	689	BURNSVILLE CHAMBER OF COMMERCE	10.00	11/30/2018	362640	P JOHNSON 11/13 LUNCHEON	43709	COMMREL
114	3226	US BANK-MNCHAMBER	225.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	DEYOE
115	3226	US BANK-MNCHAMBER	(70.00)	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	DEYOE
116	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	SCHREINER
117	3226	US BANK-DAKOTA CO. REG. CHAMBER	75.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	COMMREL
118	3226	US BANK-BURNSVILLE ROTARY	105.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	COMMREL
119	3226	US BANK-BENEFICIAL ELECTRIFICATION LEAGUE	99.92	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	DEYOE
120	3226	US BANK-BURNSVILLE ROTARY	70.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	DEYOE
121	3226	US BANK-DAKOTA CO. REG. CHAMBER	150.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	DEYOE
122	3226	US BANK-360 COMMUNITIES	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	DEYOE
123	3226	US BANK-BURNSVILLE ROTARY	35.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	LEKSON
124	3226	US BANK-360 COMMUNITIES	150.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	LEKSON
125	3226	US BANK-360 COMMUNITIES	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	PITTMAN
126	3226	US BANK-MNCHAMBER	75.00	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	SCHREINER
127	3226	US BANK-360 COMMUNITIES	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	SCHREINER
128	3226	US BANK-BURNSVILLE ROTARY	70.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	SHELDON
129	3226	US BANK-BENEFICIAL ELECTRIFICATION LEAGUE	99.92	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	VAN
130	4060	MINNESOTA CHAMBER OF COMMERCE	60.00	12/31/2018	364319	11/15/18-LUNCH	AM2018-102018-1932	COMMREL
131	875	APPLE VALLEY CHAMBER OF COMM	20.00	12/31/2018	364565	DEC LUCH-JOHNSON.POULSON	22559	AEN
132	875	APPLE VALLEY CHAMBER OF COMM	20.00	12/31/2018	364565	DEC LUCH-JOHNSON.POULSON	22559	ECO
133	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	COMMREL
134	653	LAKEVILLE AREA CHAMBER OF COMM	60.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	DEYOE
135	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	JONES
136	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	LEKSON
137	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	PITTMAN
138	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	SCHREINER
139	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	VAN
140	3226	US BANK-DAKOTA CO. REG. CHAMBER	25.00	12/31/2018	2009534	CC Recap-Julie A Simonsen	12/2018-JAS	COMMREL
141	3226	US BANK-MNCHAMBER	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	COMMREL
142	3226	US BANK-MNCHAMBER	850.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	COMMREL
143	3226	US BANK-MNCHAMBER	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	LEKSON
144	3226	US BANK-MNCHAMBER	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	SCHREINER
145	3226	US BANK-MNCHAMBER	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	VAN

Total Company - Community Events **$ 15,929.10**

Workpaper 15E
Board of Directors
Compensation & Expenses

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
1	81610	Education & Training Fees	3226	US BANK	600.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	SHELDON
2	81610	Education & Training Fees	3226	US BANK	1,509.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	DEYOE
3	81610	Education & Training Fees	3226	US BANK	1,259.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	PTRAPP
4	81610	Education & Training Fees	337	MN RURAL ELECTRIC ASSOCIATION	335.00	3/31/2018	357199	ANNUAL MTG 3/15-16	INV00013226	4/12/2018	DEYOE
5	81610	Education & Training Fees	3226	US BANK	(425.00)	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	SHELDON
6	81610	Education & Training Fees	337	MN RURAL ELECTRIC ASSOCIATION	239.00	8/31/2018	360925	BOARD CHAIR RNDTBL 8/7/18	INV00013615	8/30/2018	JONES
7	81610	Education & Training Fees	337	MN RURAL ELECTRIC ASSOCIATION	434.00	8/31/2018	361060	ENERGY ISSUES SUMMIT 8/7-8/9	INV00013638	9/6/2018	DANNER
8	81610	Education & Training Fees	337	MN RURAL ELECTRIC ASSOCIATION	434.00	8/31/2018	361060	ENERGY ISSUES SUMMIT 8/7-8/9	INV00013638	9/6/2018	LEKSON
9	81610	Education & Training Fees	337	MN RURAL ELECTRIC ASSOCIATION	434.00	8/31/2018	361060	ENERGY ISSUES SUMMIT 8/7-8/9	INV00013638	9/6/2018	PTRAPP
10	81610	Education & Training Fees	3226	US BANK	1,074.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	DEYOE
11	81610	Education & Training Fees	3226	US BANK	465.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	PTRAPP
12	81610	Education & Training Fees	3226	US BANK	875.00	11/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	PITTMAN
13	81610	Education & Training Fees	3226	US BANK	875.00	11/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	SCHREINER
14	81610	Education & Training Fees	3226	US BANK	875.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	JONES
				BOD Total Education & Training	**$ 8,983.00**						
15	82310	Bank Service Charges	2625	JANET L LEKSON	95.00	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
16	82310	Bank Service Charges	8207	JOHN D DEYOE	99.00	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
17	82310	Bank Service Charges	3048	MARGARET D SCHREINER	100.00	4/30/2018	3037	EXPENSE REPORT	APR/2018	5/1/2018	SCHREINER
18	82310	Bank Service Charges	8060	DAVID S JONES	85.00	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
19	82310	Bank Service Charges	5886	KENNETH H DANNER	95.00	10/31/2018	3238	EXPENSE REPORT	OCT/2018	10/31/2018	DANNER
20	82310	Bank Service Charges	3227	JUDITH H KIMMES	95.00	11/30/2018	3281	EXPENSE REPORT	NOV/2018	12/7/2018	KIMMES
				Total BOD Bank Service Charges	**$ 569.00**						
21	82410	Board Fees	4919	CLAY VAN DE BOGART	2,525.00	1/31/2018	355790	EXPENSE REPORT	JAN/2018	1/30/2018	VAN
22	82410	Board Fees	8060	DAVID S JONES	2,525.00	1/31/2018	2912	EXPENSE REPORT	JAN/2018	1/31/2018	JONES
23	82410	Board Fees	2305	GERALD F PITTMAN JR	2,525.00	1/31/2018	2915	EXPENSE REPORT	JAN/2018	1/31/2018	PITTMAN
24	82410	Board Fees	3052	JAMES F SHELDON	3,282.50	1/31/2018	2918	EXPENSE REPORT	JAN/2018	1/31/2018	SHELDON
25	82410	Board Fees	2625	JANET L LEKSON	2,525.00	1/31/2018	2914	EXPENSE REPORT	JAN/2018	1/31/2018	LEKSON
26	82410	Board Fees	8207	JOHN D DEYOE	2,525.00	1/31/2018	2909	EXPENSE REPORT	JAN/2018	1/31/2018	DEYOE
27	82410	Board Fees	3227	JUDITH H KIMMES	2,525.00	1/31/2018	2913	EXPENSE REPORT	JAN/2018	1/31/2018	KIMMES
28	82410	Board Fees	5886	KENNETH H DANNER	2,525.00	1/31/2018	2908	EXPENSE REPORT	JAN/2018	1/31/2018	DANNER
29	82410	Board Fees	3048	MARGARET D SCHREINER	2,525.00	1/31/2018	2916	EXPENSE REPORT	JAN/2018	1/31/2018	SCHREINER
30	82410	Board Fees	5426	PAUL A TRAPP	2,525.00	1/31/2018	2919	EXPENSE REPORT	JAN/2018	1/31/2018	PTRAPP
31	82410	Board Fees	7867	PAUL D R BAKKEN	2,525.00	1/31/2018	2906	EXPENSE REPORT	JAN/2018	1/31/2018	BAKKEN
32	82410	Board Fees	3046	WILLIAM F HOLTON	2,525.00	1/31/2018	2911	EXPENSE REPORT	JAN/2018	1/31/2018	HOLTON
33	82410	Board Fees	4919	CLAY VAN DE BOGART	2,525.00	2/28/2018	356407	EXPENSE REPORT	FEB/2018	2/27/2018	VAN
34	82410	Board Fees	8060	DAVID S JONES	2,525.00	2/28/2018	2949	EXPENSE REPORT	FEB/2018	2/28/2018	JONES
35	82410	Board Fees	2305	GERALD F PITTMAN JR	2,525.00	2/28/2018	2953	EXPENSE REPORT	FEB/2018	2/28/2018	PITTMAN
36	82410	Board Fees	3052	JAMES F SHELDON	3,282.50	2/28/2018	2956	EXPENSE REPORT	FEB/2018	2/28/2018	SHELDON
37	82410	Board Fees	2625	JANET L LEKSON	2,525.00	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
38	82410	Board Fees	8207	JOHN D DEYOE	2,525.00	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
39	82410	Board Fees	3227	JUDITH H KIMMES	2,525.00	2/28/2018	2951	EXPENSE REPORT	FEB/2018	2/28/2018	KIMMES
40	82410	Board Fees	5886	KENNETH H DANNER	2,525.00	2/28/2018	2944	EXPENSE REPORT	FEB/2018	2/28/2018	DANNER
41	82410	Board Fees	3048	MARGARET D SCHREINER	2,525.00	2/28/2018	2955	EXPENSE REPORT	FEB/2018	2/28/2018	SCHREINER
42	82410	Board Fees	5426	PAUL A TRAPP	2,525.00	2/28/2018	2957	EXPENSE REPORT	FEB/2018	2/28/2018	PTRAPP
43	82410	Board Fees	7867	PAUL D R BAKKEN	2,525.00	2/28/2018	2942	EXPENSE REPORT	FEB/2018	2/28/2018	BAKKEN
44	82410	Board Fees	3046	WILLIAM F HOLTON	2,525.00	2/28/2018	2948	EXPENSE REPORT	FEB/2018	2/28/2018	HOLTON
45	82410	Board Fees	4919	CLAY VAN DE BOGART	2,525.00	3/31/2018	356922	EXPENSE REPORT	MAR/2018	3/27/2018	VAN
46	82410	Board Fees	8060	DAVID S JONES	2,525.00	3/31/2018	2988	EXPENSE REPORT	MAR/2018	3/28/2018	JONES
47	82410	Board Fees	2305	GERALD F PITTMAN JR	2,525.00	3/31/2018	2993	EXPENSE REPORT	MAR/2018	3/28/2018	PITTMAN
48	82410	Board Fees	3052	JAMES F SHELDON	3,282.50	3/31/2018	2995	EXPENSE REPORT	MAR/2018	3/28/2018	SHELDON
49	82410	Board Fees	2625	JANET L LEKSON	2,525.00	3/31/2018	2991	EXPENSE REPORT	MAR/2018	3/28/2018	LEKSON
50	82410	Board Fees	8207	JOHN D DEYOE	2,525.00	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
51	82410	Board Fees	3227	JUDITH H KIMMES	2,525.00	3/31/2018	2990	EXPENSE REPORT	MAR/2018	3/28/2018	KIMMES
52	82410	Board Fees	5886	KENNETH H DANNER	2,525.00	3/31/2018	2982	EXPENSE REPORT	MAR/2018	3/28/2018	DANNER

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
53	82410	Board Fees	3048	MARGARET D SCHREINER	2,525.00	3/31/2018	2994	EXPENSE REPORT	MAR/2018	3/28/2018	SCHREINER
54	82410	Board Fees	5426	PAUL A TRAPP	2,525.00	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
55	82410	Board Fees	7867	PAUL D R BAKKEN	2,525.00	3/31/2018	2980	EXPENSE REPORT	MAR/2018	3/28/2018	BAKKEN
56	82410	Board Fees	3046	WILLIAM F HOLTON	2,525.00	3/31/2018	2987	EXPENSE REPORT	MAR/2018	3/28/2018	HOLTON
57	82410	Board Fees	4919	CLAY VAN DE BOGART	2,525.00	4/30/2018	357654	EXPENSE REPORT	APR/2018	5/1/2018	VAN
58	82410	Board Fees	8060	DAVID S JONES	2,525.00	4/30/2018	3032	EXPENSE REPORT	APR/2018	5/1/2018	JONES
59	82410	Board Fees	2305	GERALD F PITTMAN JR	2,525.00	4/30/2018	3035	EXPENSE REPORT	APR/2018	5/1/2018	PITTMAN
60	82410	Board Fees	3052	JAMES F SHELDON	3,282.50	4/30/2018	3038	EXPENSE REPORT	APR/2018	5/1/2018	SHELDON
61	82410	Board Fees	2625	JANET L LEKSON	2,525.00	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
62	82410	Board Fees	8207	JOHN D DEYOE	2,525.00	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
63	82410	Board Fees	3227	JUDITH H KIMMES	2,525.00	4/30/2018	3033	EXPENSE REPORT	APR/2018	5/1/2018	KIMMES
64	82410	Board Fees	5886	KENNETH H DANNER	2,525.00	4/30/2018	3027	EXPENSE REPORT	APR/2018	5/1/2018	DANNER
65	82410	Board Fees	3048	MARGARET D SCHREINER	2,525.00	4/30/2018	3037	EXPENSE REPORT	APR/2018	5/1/2018	SCHREINER
66	82410	Board Fees	5426	PAUL A TRAPP	2,525.00	4/30/2018	3039	EXPENSE REPORT	APR/2018	5/1/2018	PTRAPP
67	82410	Board Fees	7867	PAUL D R BAKKEN	2,525.00	4/30/2018	3026	EXPENSE REPORT	APR/2018	5/1/2018	BAKKEN
68	82410	Board Fees	3046	WILLIAM F HOLTON	2,525.00	4/30/2018	3031	EXPENSE REPORT	APR/2018	5/1/2018	HOLTON
69	82410	Board Fees	4919	CLAY VAN DE BOGART	2,525.00	5/31/2018	358598	EXPENSE REPORT	MAY/2018	6/7/2018	VAN
70	82410	Board Fees	8060	DAVID S JONES	2,525.00	5/31/2018	3071	EXPENSE REPORT	MAY/2018	6/8/2018	JONES
71	82410	Board Fees	2305	GERALD F PITTMAN JR	2,525.00	5/31/2018	3076	EXPENSE REPORT	MAY/2018	6/8/2018	PITTMAN
72	82410	Board Fees	3052	JAMES F SHELDON	3,282.50	5/31/2018	3078	EXPENSE REPORT	MAY/2018	6/8/2018	SHELDON
73	82410	Board Fees	2625	JANET L LEKSON	2,525.00	5/31/2018	358517	EXPENSE REPORT	MAY/2018	6/4/2018	LEKSON
74	82410	Board Fees	8207	JOHN D DEYOE	2,525.00	5/31/2018	3068	EXPENSE REPORT	MAY/2018	6/8/2018	DEYOE
75	82410	Board Fees	3227	JUDITH H KIMMES	2,525.00	5/31/2018	3073	EXPENSE REPORT	MAY/2018	6/8/2018	KIMMES
76	82410	Board Fees	5886	KENNETH H DANNER	2,525.00	5/31/2018	3067	EXPENSE REPORT	MAY/2018	6/8/2018	DANNER
77	82410	Board Fees	3048	MARGARET D SCHREINER	2,525.00	5/31/2018	3077	EXPENSE REPORT	MAY/2018	6/8/2018	SCHREINER
78	82410	Board Fees	5426	PAUL A TRAPP	2,525.00	5/31/2018	3079	EXPENSE REPORT	MAY/2018	6/8/2018	PTRAPP
79	82410	Board Fees	7867	PAUL D R BAKKEN	2,525.00	5/31/2018	3066	EXPENSE REPORT	MAY/2018	6/8/2018	BAKKEN
80	82410	Board Fees	3046	WILLIAM F HOLTON	2,525.00	5/31/2018	3070	EXPENSE REPORT	MAY/2018	6/8/2018	HOLTON
81	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	6/30/2018	359175	EXPENSE REPORT	JUNE/2018	7/3/2018	VAN
82	82410	Board Fees	8060	DAVID S JONES	3,347.50	6/30/2018	3099	EXPENSE REPORT	JUNE/2018	7/5/2018	JONES
83	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	6/30/2018	3102	EXPENSE REPORT	JUNE/2018	7/5/2018	PITTMAN
84	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	6/30/2018	3104	EXPENSE REPORT	JUNE/2018	7/5/2018	SHELDON
85	82410	Board Fees	2625	JANET L LEKSON	2,575.00	6/30/2018	3101	EXPENSE REPORT	JUNE/2018	7/5/2018	LEKSON
86	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	6/30/2018	3097	EXPENSE REPORT	JUNE/2018	7/5/2018	DEYOE
87	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	6/30/2018	3100	EXPENSE REPORT	JUNE/2018	7/5/2018	KIMMES
88	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	6/30/2018	3096	EXPENSE REPORT	JUNE/2018	7/5/2018	DANNER
89	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	6/30/2018	3103	EXPENSE REPORT	JUNE/2018	7/5/2018	SCHREINER
90	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
91	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	6/30/2018	3095	EXPENSE REPORT	JUNE/2018	7/5/2018	BAKKEN
92	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	6/30/2018	3098	EXPENSE REPORT	JUNE/2018	7/5/2018	HOLTON
93	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	7/31/2018	360064	EXPENSE REPORT	JULY/2018	7/31/2018	VAN
94	82410	Board Fees	8060	DAVID S JONES	3,347.50	7/31/2018	3134	EXPENSE REPORT	JULY/2018	7/31/2018	JONES
95	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	7/31/2018	3137	EXPENSE REPORT	JULY/2018	7/31/2018	PITTMAN
96	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	7/31/2018	3139	EXPENSE REPORT	JULY/2018	7/31/2018	SHELDON
97	82410	Board Fees	2625	JANET L LEKSON	2,575.00	7/31/2018	3136	EXPENSE REPORT	JULY/2018	7/31/2018	LEKSON
98	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	7/31/2018	3132	EXPENSE REPORT	JULY/2018	7/31/2018	DEYOE
99	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	7/31/2018	3135	EXPENSE REPORT	JULY/2018	7/31/2018	KIMMES
100	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	7/31/2018	3131	EXPENSE REPORT	JULY/2018	7/31/2018	DANNER
101	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	7/31/2018	3138	EXPENSE REPORT	JULY/2018	7/31/2018	SCHREINER
102	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	7/31/2018	3140	EXPENSE REPORT	JULY/2018	7/31/2018	PTRAPP
103	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	7/31/2018	3130	EXPENSE REPORT	JULY/2018	7/31/2018	BAKKEN
104	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	7/31/2018	3133	EXPENSE REPORT	JULY/2018	7/31/2018	HOLTON
105	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	8/31/2018	361027	EXPENSE REPORT	AUG/2018	9/4/2018	VAN
106	82410	Board Fees	8060	DAVID S JONES	3,347.50	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
107	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	8/31/2018	3177	EXPENSE REPORT	AUG/2018	9/4/2018	PITTMAN
108	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	8/31/2018	3179	EXPENSE REPORT	AUG/2018	9/4/2018	SHELDON

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
109	82410	Board Fees	2625	JANET L LEKSON	2,575.00	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
110	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	8/31/2018	3172	EXPENSE REPORT	AUG/2018	9/4/2018	DEYOE
111	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	8/31/2018	3175	EXPENSE REPORT	AUG/2018	9/4/2018	KIMMES
112	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
113	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	8/31/2018	3178	EXPENSE REPORT	AUG/2018	9/4/2018	SCHREINER
114	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
115	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	8/31/2018	3170	EXPENSE REPORT	AUG/2018	9/4/2018	BAKKEN
116	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	8/31/2018	3173	EXPENSE REPORT	AUG/2018	9/4/2018	HOLTON
117	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	9/30/2018	361788	EXPENSE REPORT	SEPT/2018	10/2/2018	VAN
118	82410	Board Fees	8060	DAVID S JONES	3,347.50	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
119	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	9/30/2018	3213	EXPENSE REPORT	SEPT/2018	10/3/2018	PITTMAN
120	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	9/30/2018	3215	EXPENSE REPORT	SEPT/2018	10/3/2018	SHELDON
121	82410	Board Fees	2625	JANET L LEKSON	2,575.00	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
122	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
123	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	9/30/2018	3210	EXPENSE REPORT	SEPT/2018	10/3/2018	KIMMES
124	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	9/30/2018	3204	EXPENSE REPORT	SEPT/2018	10/3/2018	DANNER
125	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	9/30/2018	3214	EXPENSE REPORT	SEPT/2018	10/3/2018	SCHREINER
126	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
127	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	9/30/2018	3202	EXPENSE REPORT	SEPT/2018	10/3/2018	BAKKEN
128	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	9/30/2018	3208	EXPENSE REPORT	SEPT/2018	10/3/2018	HOLTON
129	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	10/31/2018	362565	EXPENSE REPORT	OCT/2018	10/30/2018	VAN
130	82410	Board Fees	8060	DAVID S JONES	3,347.50	10/31/2018	3242	EXPENSE REPORT	OCT/2018	10/31/2018	JONES
131	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	10/31/2018	3245	EXPENSE REPORT	OCT/2018	10/31/2018	PITTMAN
132	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	10/31/2018	3247	EXPENSE REPORT	OCT/2018	10/31/2018	SHELDON
133	82410	Board Fees	2625	JANET L LEKSON	2,575.00	10/31/2018	3244	EXPENSE REPORT	OCT/2018	10/31/2018	LEKSON
134	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	10/31/2018	3239	EXPENSE REPORT	OCT/2018	10/31/2018	DEYOE
135	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	10/31/2018	3243	EXPENSE REPORT	OCT/2018	10/31/2018	KIMMES
136	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	10/31/2018	3238	EXPENSE REPORT	OCT/2018	10/31/2018	DANNER
137	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	10/31/2018	3246	EXPENSE REPORT	OCT/2018	10/31/2018	SCHREINER
138	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	10/31/2018	3248	EXPENSE REPORT	OCT/2018	10/31/2018	PTRAPP
139	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	10/31/2018	3236	EXPENSE REPORT	OCT/2018	10/31/2018	BAKKEN
140	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	10/31/2018	3241	EXPENSE REPORT	OCT/2018	10/31/2018	HOLTON
141	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	11/30/2018	363764	EXPENSE REPORT	NOV/2018	12/6/2018	VAN
142	82410	Board Fees	8060	DAVID S JONES	3,347.50	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
143	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
144	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	11/30/2018	3286	EXPENSE REPORT	NOV/2018	12/7/2018	SHELDON
145	82410	Board Fees	2625	JANET L LEKSON	2,575.00	11/30/2018	3282	EXPENSE REPORT	NOV/2018	12/7/2018	LEKSON
146	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	11/30/2018	3276	EXPENSE REPORT	NOV/2018	12/7/2018	DEYOE
147	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	11/30/2018	3281	EXPENSE REPORT	NOV/2018	12/7/2018	KIMMES
148	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	11/30/2018	3275	EXPENSE REPORT	NOV/2018	12/7/2018	DANNER
149	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
150	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	11/30/2018	3287	EXPENSE REPORT	NOV/2018	12/7/2018	PTRAPP
151	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	11/30/2018	3274	EXPENSE REPORT	NOV/2018	12/7/2018	BAKKEN
152	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	11/30/2018	3278	EXPENSE REPORT	NOV/2018	12/7/2018	HOLTON
153	82410	Board Fees	4919	CLAY VAN DE BOGART	2,575.00	12/31/2018	364418	EXPENSE REPORT	DEC/2018	12/27/2018	VAN
154	82410	Board Fees	8060	DAVID S JONES	3,347.50	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
155	82410	Board Fees	2305	GERALD F PITTMAN JR	2,575.00	12/31/2018	3311	EXPENSE REPORT	DEC/2018	12/28/2018	PITTMAN
156	82410	Board Fees	3052	JAMES F SHELDON	2,575.00	12/31/2018	3314	EXPENSE REPORT	DEC/2018	12/28/2018	SHELDON
157	82410	Board Fees	2625	JANET L LEKSON	2,575.00	12/31/2018	3309	EXPENSE REPORT	DEC/2018	12/28/2018	LEKSON
158	82410	Board Fees	8207	JOHN D DEYOE	2,575.00	12/31/2018	3303	EXPENSE REPORT	DEC/2018	12/28/2018	DEYOE
159	82410	Board Fees	3227	JUDITH H KIMMES	2,575.00	12/31/2018	3307	EXPENSE REPORT	DEC/2018	12/28/2018	KIMMES
160	82410	Board Fees	5886	KENNETH H DANNER	2,575.00	12/31/2018	3302	EXPENSE REPORT	DEC/2018	12/28/2018	DANNER
161	82410	Board Fees	3048	MARGARET D SCHREINER	2,575.00	12/31/2018	3313	EXPENSE REPORT	DEC/2018	12/28/2018	SCHREINER
162	82410	Board Fees	5426	PAUL A TRAPP	2,575.00	12/31/2018	3315	EXPENSE REPORT	DEC/2018	12/28/2018	PTRAPP
163	82410	Board Fees	7867	PAUL D R BAKKEN	2,575.00	12/31/2018	3301	EXPENSE REPORT	DEC/2018	12/28/2018	BAKKEN
164	82410	Board Fees	3046	WILLIAM F HOLTON	2,575.00	12/31/2018	3305	EXPENSE REPORT	DEC/2018	12/28/2018	HOLTON

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
				Total Board Fees	**$ 376,995.00**						
165	83610	Dues & Memberships	5411	BURNSVILLE ROTARY FOUNDATION	400.00	1/31/2018	355488	J SHELDON 1/1-6/30/18	1111801	1/18/2018	SHELDON
166	83610	Dues & Memberships	5411	BURNSVILLE ROTARY FOUNDATION	350.00	7/31/2018	360423	J SHELDON 7/1-12/31/18	180730	8/14/2018	SHELDON
				Total Dues & Memberships	**$ 750.00**						
167	84110	Office Supplies	2625	JANET L LEKSON	10.00	6/30/2018	3101	EXPENSE REPORT	JUNE/2018-C	43286	LEKSON
				Total Office Supplies	**$ 10.00**						
168	84120	Printing	5886	KENNETH H DANNER	29.25	1/31/2018	2908	EXPENSE REPORT	JAN/2018	1/31/2018	DANNER
169	84121	Printing	3825	CREATIVE GRAPHICS PRIOR LAKE	119.85	6/30/2018	359326	BUSINESS CARDS/D JONES	00086832	7/10/2018	JONES
				Total Outside Printing	**$ 149.10**						
170	84510	Airfare	8207	JOHN D DEYOE	230.95	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
171	84510	Airfare	5426	PAUL A TRAPP	496.66	2/28/2018	2957	EXPENSE REPORT	FEB/2018	2/28/2018	PTRAPP
172	84510	Airfare	2625	JANET L LEKSON	280.13	2/28/2018	2914	EXPENSE REPORT (Accrual)	JAN/2018	1/31/2018	LEKSON
173	84510	Airfare	2625	JANET L LEKSON	516.50	5/31/2018	2991	EXPENSE REPORT (Accrual)	MAR/2018	3/28/2018	LEKSON
174	84510	Airfare	2625	JANET L LEKSON	386.40	9/30/2018	3136	EXPENSE REPORT (Accrual)	JUL/2018	7/31/2018	LEKSON
175	84510	Airfare	8060	DAVID S JONES	411.40	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
176	84510	Airfare	2305	GERALD F PITTMAN JR	330.40	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
177	84510	Airfare	3048	MARGARET D SCHREINER	311.40	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
				Total Airfare	**$ 2,963.84**						
178	84520	Mileage	4919	CLAY VAN DE BOGART	50.14	1/31/2018	355790	EXPENSE REPORT	JAN/2018	1/30/2018	VAN
179	84520	Mileage	8060	DAVID S JONES	10.90	1/31/2018	2912	EXPENSE REPORT	JAN/2018	1/31/2018	JONES
180	84520	Mileage	2305	GERALD F PITTMAN JR	13.08	1/31/2018	2915	EXPENSE REPORT	JAN/2018	1/31/2018	PITTMAN
181	84520	Mileage	3052	JAMES F SHELDON	30.52	1/31/2018	2918	EXPENSE REPORT	JAN/2018	1/31/2018	SHELDON
182	84520	Mileage	2625	JANET L LEKSON	31.07	1/31/2018	2914	EXPENSE REPORT	JAN/2018	1/31/2018	LEKSON
183	84520	Mileage	8207	JOHN D DEYOE	21.80	1/31/2018	2909	EXPENSE REPORT	JAN/2018	1/31/2018	DEYOE
184	84520	Mileage	3227	JUDITH H KIMMES	55.59	1/31/2018	2913	EXPENSE REPORT	JAN/2018	1/31/2018	KIMMES
185	84520	Mileage	5886	KENNETH H DANNER	10.90	1/31/2018	2908	EXPENSE REPORT	JAN/2018	1/31/2018	DANNER
186	84520	Mileage	3048	MARGARET D SCHREINER	81.75	1/31/2018	2916	EXPENSE REPORT	JAN/2018	1/31/2018	SCHREINER
187	84520	Mileage	5426	PAUL A TRAPP	21.80	1/31/2018	2919	EXPENSE REPORT	JAN/2018	1/31/2018	PTRAPP
188	84520	Mileage	7867	PAUL D R BAKKEN	15.26	1/31/2018	2906	EXPENSE REPORT	JAN/2018	1/31/2018	BAKKEN
189	84520	Mileage	3046	WILLIAM F HOLTON	10.90	1/31/2018	2911	EXPENSE REPORT	JAN/2018	1/31/2018	HOLTON
190	84520	Mileage	4919	CLAY VAN DE BOGART	35.97	2/28/2018	356407	EXPENSE REPORT	FEB/2018	2/27/2018	VAN
191	84520	Mileage	8060	DAVID S JONES	21.80	2/28/2018	2949	EXPENSE REPORT	FEB/2018	2/28/2018	JONES
192	84520	Mileage	2305	GERALD F PITTMAN JR	78.70	2/28/2018	2953	EXPENSE REPORT	FEB/2018	2/28/2018	PITTMAN
193	84520	Mileage	3052	JAMES F SHELDON	32.70	2/28/2018	2956	EXPENSE REPORT	FEB/2018	2/28/2018	SHELDON
194	84520	Mileage	2625	JANET L LEKSON	97.01	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
195	84520	Mileage	8207	JOHN D DEYOE	87.21	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
196	84520	Mileage	3227	JUDITH H KIMMES	30.52	2/28/2018	2951	EXPENSE REPORT	FEB/2018	2/28/2018	KIMMES
197	84520	Mileage	5886	KENNETH H DANNER	21.80	2/28/2018	2944	EXPENSE REPORT	FEB/2018	2/28/2018	DANNER
198	84520	Mileage	3048	MARGARET D SCHREINER	78.48	2/28/2018	2955	EXPENSE REPORT	FEB/2018	2/28/2018	SCHREINER
199	84520	Mileage	5426	PAUL A TRAPP	46.33	2/28/2018	2957	EXPENSE REPORT	FEB/2018	2/28/2018	PTRAPP
200	84520	Mileage	7867	PAUL D R BAKKEN	15.26	2/28/2018	2942	EXPENSE REPORT	FEB/2018	2/28/2018	BAKKEN
201	84520	Mileage	3046	WILLIAM F HOLTON	10.90	2/28/2018	2948	EXPENSE REPORT	FEB/2018	2/28/2018	HOLTON
202	84520	Mileage	4919	CLAY VAN DE BOGART	37.06	3/31/2018	356922	EXPENSE REPORT	MAR/2018	3/27/2018	VAN
203	84520	Mileage	8060	DAVID S JONES	10.90	3/31/2018	2988	EXPENSE REPORT	MAR/2018	3/28/2018	JONES
204	84520	Mileage	2305	GERALD F PITTMAN JR	76.19	3/31/2018	2993	EXPENSE REPORT	MAR/2018	3/28/2018	PITTMAN
205	84520	Mileage	2625	JANET L LEKSON	18.53	3/31/2018	2991	EXPENSE REPORT	MAR/2018	3/28/2018	LEKSON
206	84520	Mileage	8207	JOHN D DEYOE	297.03	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
207	84520	Mileage	3227	JUDITH H KIMMES	56.68	3/31/2018	2990	EXPENSE REPORT	MAR/2018	3/28/2018	KIMMES
208	84520	Mileage	5886	KENNETH H DANNER	126.44	3/31/2018	2982	EXPENSE REPORT	MAR/2018	3/28/2018	DANNER
209	84520	Mileage	3048	MARGARET D SCHREINER	64.31	3/31/2018	2994	EXPENSE REPORT	MAR/2018	3/28/2018	SCHREINER
210	84520	Mileage	5426	PAUL A TRAPP	43.60	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
211	84520	Mileage	7867	PAUL D R BAKKEN	15.26	3/31/2018	2980	EXPENSE REPORT	MAR/2018	3/28/2018	BAKKEN
212	84520	Mileage	3046	WILLIAM F HOLTON	10.90	3/31/2018	2987	EXPENSE REPORT	MAR/2018	3/28/2018	HOLTON
213	84520	Mileage	4919	CLAY VAN DE BOGART	63.22	4/30/2018	357654	EXPENSE REPORT	APR/2018	5/1/2018	VAN
214	84520	Mileage	8060	DAVID S JONES	10.90	4/30/2018	3032	EXPENSE REPORT	APR/2018	5/1/2018	JONES
215	84520	Mileage	2305	GERALD F PITTMAN JR	51.23	4/30/2018	3035	EXPENSE REPORT	APR/2018	5/1/2018	PITTMAN
216	84520	Mileage	3052	JAMES F SHELDON	46.87	4/30/2018	3038	EXPENSE REPORT	APR/2018	5/1/2018	SHELDON
217	84520	Mileage	2625	JANET L LEKSON	65.40	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
218	84520	Mileage	8207	JOHN D DEYOE	117.18	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
219	84520	Mileage	3227	JUDITH H KIMMES	46.87	4/30/2018	3033	EXPENSE REPORT	APR/2018	5/1/2018	KIMMES
220	84520	Mileage	5886	KENNETH H DANNER	47.96	4/30/2018	3027	EXPENSE REPORT	APR/2018	5/1/2018	DANNER
221	84520	Mileage	3048	MARGARET D SCHREINER	73.03	4/30/2018	3037	EXPENSE REPORT	APR/2018	5/1/2018	SCHREINER
222	84520	Mileage	5426	PAUL A TRAPP	65.40	4/30/2018	3039	EXPENSE REPORT	APR/2018	5/1/2018	PTRAPP
223	84520	Mileage	7867	PAUL D R BAKKEN	15.26	4/30/2018	3026	EXPENSE REPORT	APR/2018	5/1/2018	BAKKEN
224	84520	Mileage	3046	WILLIAM F HOLTON	21.80	4/30/2018	3031	EXPENSE REPORT	APR/2018	5/1/2018	HOLTON
225	84520	Mileage	4919	CLAY VAN DE BOGART	53.42	5/31/2018	358598	EXPENSE REPORT	MAY/2018	6/7/2018	VAN
226	84520	Mileage	8060	DAVID S JONES	16.35	5/31/2018	3071	EXPENSE REPORT	MAY/2018	6/8/2018	JONES
227	84520	Mileage	2305	GERALD F PITTMAN JR	44.15	5/31/2018	3076	EXPENSE REPORT	MAY/2018	6/8/2018	PITTMAN
228	84520	Mileage	3052	JAMES F SHELDON	46.87	5/31/2018	3078	EXPENSE REPORT	MAY/2018	6/8/2018	SHELDON
229	84520	Mileage	2625	JANET L LEKSON	21.80	5/31/2018	358517	EXPENSE REPORT	MAY/2018	6/4/2018	LEKSON
230	84520	Mileage	8207	JOHN D DEYOE	95.38	5/31/2018	3068	EXPENSE REPORT	MAY/2018	6/8/2018	DEYOE
231	84520	Mileage	3227	JUDITH H KIMMES	93.74	5/31/2018	3073	EXPENSE REPORT	MAY/2018	6/8/2018	KIMMES
232	84520	Mileage	5886	KENNETH H DANNER	34.88	5/31/2018	3067	EXPENSE REPORT	MAY/2018	6/8/2018	DANNER
233	84520	Mileage	3048	MARGARET D SCHREINER	99.19	5/31/2018	3077	EXPENSE REPORT	MAY/2018	6/8/2018	SCHREINER
234	84520	Mileage	5426	PAUL A TRAPP	81.75	5/31/2018	3079	EXPENSE REPORT	MAY/2018	6/8/2018	PTRAPP
235	84520	Mileage	7867	PAUL D R BAKKEN	15.26	5/31/2018	3066	EXPENSE REPORT	MAY/2018	6/8/2018	BAKKEN
236	84520	Mileage	3046	WILLIAM F HOLTON	21.80	5/31/2018	3070	EXPENSE REPORT	MAY/2018	6/8/2018	HOLTON
237	84520	Mileage	4919	CLAY VAN DE BOGART	11.99	6/30/2018	359175	EXPENSE REPORT	JUNE/2018	7/3/2018	VAN
238	84520	Mileage	8060	DAVID S JONES	62.68	6/30/2018	3099	EXPENSE REPORT	JUNE/2018	7/5/2018	JONES
239	84520	Mileage	2305	GERALD F PITTMAN JR	13.08	6/30/2018	3102	EXPENSE REPORT	JUNE/2018	7/5/2018	PITTMAN
240	84520	Mileage	3052	JAMES F SHELDON	39.24	6/30/2018	3104	EXPENSE REPORT	JUNE/2018	7/5/2018	SHELDON
241	84520	Mileage	2625	JANET L LEKSON	9.81	6/30/2018	3101	EXPENSE REPORT	JUNE/2018	7/5/2018	LEKSON
242	84520	Mileage	8207	JOHN D DEYOE	129.71	6/30/2018	3097	EXPENSE REPORT	JUNE/2018	7/5/2018	DEYOE
243	84520	Mileage	3227	JUDITH H KIMMES	41.42	6/30/2018	3100	EXPENSE REPORT	JUNE/2018	7/5/2018	KIMMES
244	84520	Mileage	5886	KENNETH H DANNER	10.90	6/30/2018	3096	EXPENSE REPORT	JUNE/2018	7/5/2018	DANNER
245	84520	Mileage	3048	MARGARET D SCHREINER	16.35	6/30/2018	3103	EXPENSE REPORT	JUNE/2018	7/5/2018	SCHREINER
246	84520	Mileage	5426	PAUL A TRAPP	121.54	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
247	84520	Mileage	7867	PAUL D R BAKKEN	15.26	6/30/2018	3095	EXPENSE REPORT	JUNE/2018	7/5/2018	BAKKEN
248	84520	Mileage	3046	WILLIAM F HOLTON	10.90	6/30/2018	3098	EXPENSE REPORT	JUNE/2018	7/5/2018	HOLTON
249	84520	Mileage	4919	CLAY VAN DE BOGART	11.99	7/31/2018	360064	EXPENSE REPORT	JULY/2018	7/31/2018	VAN
250	84520	Mileage	8060	DAVID S JONES	16.35	7/31/2018	3134	EXPENSE REPORT	JULY/2018	7/31/2018	JONES
251	84520	Mileage	2305	GERALD F PITTMAN JR	13.08	7/31/2018	3137	EXPENSE REPORT	JULY/2018	7/31/2018	PITTMAN
252	84520	Mileage	3052	JAMES F SHELDON	14.17	7/31/2018	3139	EXPENSE REPORT	JULY/2018	7/31/2018	SHELDON
253	84520	Mileage	2625	JANET L LEKSON	15.26	7/31/2018	3136	EXPENSE REPORT	JULY/2018	7/31/2018	LEKSON
254	84520	Mileage	8207	JOHN D DEYOE	132.44	7/31/2018	3132	EXPENSE REPORT	JULY/2018	7/31/2018	DEYOE
255	84520	Mileage	3227	JUDITH H KIMMES	42.51	7/31/2018	3135	EXPENSE REPORT	JULY/2018	7/31/2018	KIMMES
256	84520	Mileage	3048	MARGARET D SCHREINER	27.25	7/31/2018	3138	EXPENSE REPORT	JULY/2018	7/31/2018	SCHREINER
257	84520	Mileage	5426	PAUL A TRAPP	40.88	7/31/2018	3140	EXPENSE REPORT	JULY/2018	7/31/2018	PTRAPP
258	84520	Mileage	7867	PAUL D R BAKKEN	15.26	7/31/2018	3130	EXPENSE REPORT	JULY/2018	7/31/2018	BAKKEN
259	84520	Mileage	3046	WILLIAM F HOLTON	10.90	7/31/2018	3133	EXPENSE REPORT	JULY/2018	7/31/2018	HOLTON
260	84520	Mileage	4919	CLAY VAN DE BOGART	11.99	8/31/2018	361027	EXPENSE REPORT	AUG/2018	9/4/2018	VAN
261	84520	Mileage	8060	DAVID S JONES	207.10	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
262	84520	Mileage	2305	GERALD F PITTMAN JR	51.78	8/31/2018	3177	EXPENSE REPORT	AUG/2018	9/4/2018	PITTMAN
263	84520	Mileage	3052	JAMES F SHELDON	28.34	8/31/2018	3179	EXPENSE REPORT	AUG/2018	9/4/2018	SHELDON
264	84520	Mileage	2625	JANET L LEKSON	104.64	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
265	84520	Mileage	8207	JOHN D DEYOE	(18.53)	8/31/2018	3172	EXPENSE REPORT	AUG/2018	9/4/2018	DEYOE
266	84520	Mileage	3227	JUDITH H KIMMES	28.34	8/31/2018	3175	EXPENSE REPORT	AUG/2018	9/4/2018	KIMMES

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
267	84520	Mileage	5886	KENNETH H DANNER	109.00	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
268	84520	Mileage	3048	MARGARET D SCHREINER	16.35	8/31/2018	3178	EXPENSE REPORT	AUG/2018	9/4/2018	SCHREINER
269	84520	Mileage	5426	PAUL A TRAPP	132.44	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
270	84520	Mileage	7867	PAUL D R BAKKEN	15.26	8/31/2018	3170	EXPENSE REPORT	AUG/2018	9/4/2018	BAKKEN
271	84520	Mileage	3046	WILLIAM F HOLTON	10.90	8/31/2018	3173	EXPENSE REPORT	AUG/2018	9/4/2018	HOLTON
272	84520	Mileage	4919	CLAY VAN DE BOGART	11.99	9/30/2018	361788	EXPENSE REPORT	SEPT/2018	10/2/2018	VAN
273	84520	Mileage	8060	DAVID S JONES	84.48	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
274	84520	Mileage	2305	GERALD F PITTMAN JR	26.16	9/30/2018	3213	EXPENSE REPORT	SEPT/2018	10/3/2018	PITTMAN
275	84520	Mileage	3052	JAMES F SHELDON	19.62	9/30/2018	3215	EXPENSE REPORT	SEPT/2018	10/3/2018	SHELDON
276	84520	Mileage	2625	JANET L LEKSON	20.71	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
277	84520	Mileage	8207	JOHN D DEYOE	141.70	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
278	84520	Mileage	3227	JUDITH H KIMMES	14.17	9/30/2018	3210	EXPENSE REPORT	SEPT/2018	10/3/2018	KIMMES
279	84520	Mileage	5886	KENNETH H DANNER	10.90	9/30/2018	3204	EXPENSE REPORT	SEPT/2018	10/3/2018	DANNER
280	84520	Mileage	3048	MARGARET D SCHREINER	46.87	9/30/2018	3214	EXPENSE REPORT	SEPT/2018	10/3/2018	SCHREINER
281	84520	Mileage	5426	PAUL A TRAPP	107.91	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
282	84520	Mileage	7867	PAUL D R BAKKEN	15.26	9/30/2018	3202	EXPENSE REPORT	SEPT/2018	10/3/2018	BAKKEN
283	84520	Mileage	3046	WILLIAM F HOLTON	10.90	9/30/2018	3208	EXPENSE REPORT	SEPT/2018	10/3/2018	HOLTON
284	84520	Mileage	4919	CLAY VAN DE BOGART	20.17	10/31/2018	362565	EXPENSE REPORT	OCT/2018	10/30/2018	VAN
285	84520	Mileage	8060	DAVID S JONES	19.62	10/31/2018	3242	EXPENSE REPORT	OCT/2018	10/31/2018	JONES
286	84520	Mileage	2305	GERALD F PITTMAN JR	25.62	10/31/2018	3245	EXPENSE REPORT	OCT/2018	10/31/2018	PITTMAN
287	84520	Mileage	3052	JAMES F SHELDON	37.06	10/31/2018	3247	EXPENSE REPORT	OCT/2018	10/31/2018	SHELDON
288	84520	Mileage	2625	JANET L LEKSON	20.17	10/31/2018	3244	EXPENSE REPORT	OCT/2018	10/31/2018	LEKSON
289	84520	Mileage	8207	JOHN D DEYOE	45.78	10/31/2018	3239	EXPENSE REPORT	OCT/2018	10/31/2018	DEYOE
290	84520	Mileage	3227	JUDITH H KIMMES	53.41	10/31/2018	3243	EXPENSE REPORT	OCT/2018	10/31/2018	KIMMES
291	84520	Mileage	5886	KENNETH H DANNER	26.16	10/31/2018	3238	EXPENSE REPORT	OCT/2018	10/31/2018	DANNER
292	84520	Mileage	3048	MARGARET D SCHREINER	54.50	10/31/2018	3246	EXPENSE REPORT	OCT/2018	10/31/2018	SCHREINER
293	84520	Mileage	5426	PAUL A TRAPP	79.57	10/31/2018	3248	EXPENSE REPORT	OCT/2018	10/31/2018	PTRAPP
294	84520	Mileage	7867	PAUL D R BAKKEN	34.88	10/31/2018	3236	EXPENSE REPORT	OCT/2018	10/31/2018	BAKKEN
295	84520	Mileage	3046	WILLIAM F HOLTON	21.80	10/31/2018	3241	EXPENSE REPORT	OCT/2018	10/31/2018	HOLTON
296	84520	Mileage	4919	CLAY VAN DE BOGART	66.50	11/30/2018	363764	EXPENSE REPORT	NOV/2018	12/6/2018	VAN
297	84520	Mileage	8060	DAVID S JONES	87.20	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
298	84520	Mileage	2305	GERALD F PITTMAN JR	54.72	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
299	84520	Mileage	3052	JAMES F SHELDON	61.59	11/30/2018	3286	EXPENSE REPORT	NOV/2018	12/7/2018	SHELDON
300	84520	Mileage	2625	JANET L LEKSON	35.97	11/30/2018	3282	EXPENSE REPORT	NOV/2018	12/7/2018	LEKSON
301	84520	Mileage	8207	JOHN D DEYOE	100.83	11/30/2018	3276	EXPENSE REPORT	NOV/2018	12/7/2018	DEYOE
302	84520	Mileage	3227	JUDITH H KIMMES	41.42	11/30/2018	3281	EXPENSE REPORT	NOV/2018	12/7/2018	KIMMES
303	84520	Mileage	5886	KENNETH H DANNER	10.90	11/30/2018	3275	EXPENSE REPORT	NOV/2018	12/7/2018	DANNER
304	84520	Mileage	3048	MARGARET D SCHREINER	142.79	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
305	84520	Mileage	5426	PAUL A TRAPP	46.33	11/30/2018	3287	EXPENSE REPORT	NOV/2018	12/7/2018	PTRAPP
306	84520	Mileage	7867	PAUL D R BAKKEN	15.26	11/30/2018	3274	EXPENSE REPORT	NOV/2018	12/7/2018	BAKKEN
307	84520	Mileage	3046	WILLIAM F HOLTON	34.88	11/30/2018	3278	EXPENSE REPORT	NOV/2018	12/7/2018	HOLTON
308	84520	Mileage	4919	CLAY VAN DE BOGART	11.99	12/31/2018	364418	EXPENSE REPORT	DEC/2018	12/27/2018	VAN
309	84520	Mileage	8060	DAVID S JONES	73.58	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
310	84520	Mileage	2305	GERALD F PITTMAN JR	27.96	12/31/2018	3311	EXPENSE REPORT	DEC/2018	12/28/2018	PITTMAN
311	84520	Mileage	3052	JAMES F SHELDON	44.69	12/31/2018	3314	EXPENSE REPORT	DEC/2018	12/28/2018	SHELDON
312	84520	Mileage	2625	JANET L LEKSON	26.16	12/31/2018	3309	EXPENSE REPORT	DEC/2018	12/28/2018	LEKSON
313	84520	Mileage	8207	JOHN D DEYOE	36.53	12/31/2018	3303	EXPENSE REPORT	DEC/2018	12/28/2018	DEYOE
314	84520	Mileage	3227	JUDITH H KIMMES	35.97	12/31/2018	3307	EXPENSE REPORT	DEC/2018	12/28/2018	KIMMES
315	84520	Mileage	5886	KENNETH H DANNER	10.90	12/31/2018	3302	EXPENSE REPORT	DEC/2018	12/28/2018	DANNER
316	84520	Mileage	3048	MARGARET D SCHREINER	45.78	12/31/2018	3313	EXPENSE REPORT	DEC/2018	12/28/2018	SCHREINER
317	84520	Mileage	5426	PAUL A TRAPP	65.40	12/31/2018	3315	EXPENSE REPORT	DEC/2018	12/28/2018	PTRAPP
318	84520	Mileage	7867	PAUL D R BAKKEN	15.26	12/31/2018	3301	EXPENSE REPORT	DEC/2018	12/28/2018	BAKKEN
319	84520	Mileage	3046	WILLIAM F HOLTON	21.80	12/31/2018	3305	EXPENSE REPORT	DEC/2018	12/28/2018	HOLTON
				Total Mileage	**$ 6,501.40**						
320	84545	Meals	2625	JANET L LEKSON	28.71	1/31/2018	2914	EXPENSE REPORT	JAN/2018	1/31/2018	LEKSON

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
321	84545	Meals	3048	MARGARET D SCHREINER	35.79	1/31/2018	2916	EXPENSE REPORT	JAN/2018	1/31/2018	SCHREINER
322	84545	Meals	2625	JANET L LEKSON	278.53	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
323	84545	Meals	3226	US BANK	55.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	PTRAPP
324	84545	Meals	3226	US BANK	75.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	DEYOE
325	84545	Meals	8207	JOHN D DEYOE	7.72	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
326	84545	Meals	5426	PAUL A TRAPP	131.33	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
327	84545	Meals	2625	JANET L LEKSON	309.59	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
328	84545	Meals	8207	JOHN D DEYOE	155.83	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
329	84545	Meals	4919	CLAY VAN DE BOGART	74.47	5/31/2018	358598	EXPENSE REPORT	MAY/2018	6/7/2018	VAN
330	84545	Meals	3048	MARGARET D SCHREINER	119.20	5/31/2018	3077	EXPENSE REPORT	MAY/2018	6/8/2018	SCHREINER
331	84545	Meals	5426	PAUL A TRAPP	37.89	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
332	84545	Meals	8060	DAVID S JONES	77.13	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
333	84545	Meals	2625	JANET L LEKSON	111.85	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
334	84545	Meals	5886	KENNETH H DANNER	32.87	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
335	84545	Meals	5426	PAUL A TRAPP	56.40	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
336	84545	Meals	8060	DAVID S JONES	29.61	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
337	84545	Meals	2625	JANET L LEKSON	290.07	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
338	84545	Meals	8207	JOHN D DEYOE	12.21	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
339	84545	Meals	5426	PAUL A TRAPP	43.03	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
340	84545	Meals	8060	DAVID S JONES	498.59	10/31/2018	3242	EXPENSE REPORT	OCT/2018	10/31/2018	JONES
341	84545	Meals	3226	US BANK	20.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	DEYOE
342	84545	Meals	3226	US BANK	20.00	10/31/2018	2009501	CC Recap-Cherry A. Jordan	7/2018-CAJ	7/31/2018	PTRAPP
343	84545	Meals	4919	CLAY VAN DE BOGART	24.91	11/30/2018	363764	EXPENSE REPORT	NOV/2018	12/6/2018	VAN
344	84545	Meals	8060	DAVID S JONES	228.40	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
345	84545	Meals	2305	GERALD F PITTMAN JR	131.48	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
346	84545	Meals	3048	MARGARET D SCHREINER	926.18	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
347	84545	Meals	3226	US BANK	45.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	JONES
348	84545	Meals	8060	DAVID S JONES	51.57	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
349	84545	Meals	3227	JUDITH H KIMMES	80.00	12/31/2018	3307	EXPENSE REPORT	DEC/2018	12/28/2018	KIMMES
				Total BOD Meals	**$ 3,988.36**						
350	84550	Lodging	2625	JANET L LEKSON	902.16	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
351	84551	Lodging	8207	JOHN D DEYOE	1,148.83	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
352	84552	Lodging	8207	JOHN D DEYOE	86.80	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
353	84553	Lodging	5886	KENNETH H DANNER	115.31	3/31/2018	2982	EXPENSE REPORT	MAR/2018	3/28/2018	DANNER
354	84554	Lodging	5426	PAUL A TRAPP	1,598.52	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
355	84555	Lodging	2625	JANET L LEKSON	1,259.17	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
356	84556	Lodging	5426	PAUL A TRAPP	149.21	6/30/2018	3105	EXPENSE REPORT	JUNE/2018	7/5/2018	PTRAPP
357	84557	Lodging	8060	DAVID S JONES	99.11	8/31/2018	3174	EXPENSE REPORT	AUG/2018	9/4/2018	JONES
358	84558	Lodging	2625	JANET L LEKSON	198.22	8/31/2018	3176	EXPENSE REPORT	AUG/2018	9/4/2018	LEKSON
359	84559	Lodging	5886	KENNETH H DANNER	198.22	8/31/2018	3171	EXPENSE REPORT	AUG/2018	9/4/2018	DANNER
360	84560	Lodging	5426	PAUL A TRAPP	198.22	8/31/2018	3180	EXPENSE REPORT	AUG/2018	9/4/2018	PTRAPP
361	84561	Lodging	8060	DAVID S JONES	153.63	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
362	84562	Lodging	2625	JANET L LEKSON	686.50	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
363	84563	Lodging	8207	JOHN D DEYOE	307.26	9/30/2018	3205	EXPENSE REPORT	SEPT/2018	10/3/2018	DEYOE
364	84564	Lodging	5426	PAUL A TRAPP	222.89	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
365	84565	Lodging	3226	US BANK	222.91	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	PTRAPP
366	84566	Lodging	8060	DAVID S JONES	945.00	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
367	84567	Lodging	2305	GERALD F PITTMAN JR	945.00	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
368	84568	Lodging	3048	MARGARET D SCHREINER	945.00	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
				Total Lodging	**$ 10,381.96**						
369	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	52.50	1/31/2018	355321	2018 ANNUAL MTG	29483	1/16/2018	LEKSON
370	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	1/16/2018	PITTMAN
371	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	1/16/2018	SCHREINER
372	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	105.00	1/31/2018	355321	2018 ANNUAL MTG	29483	1/16/2018	DEYOE

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
373	84560	Community Events	3226	US BANK	35.00	1/31/2018	2009471	CC Recap-Cherry A. Jordan	1/2018-CAJ	1/30/2018	DEYOE
374	84560	Community Events	676	HASTINGS AREA CHAMBER OF COMM	15.00	2/28/2018	355569	STATE OF THE CITY 2/1/18	5741	1/23/2018	KIMMES
375	84560	Community Events	4060	MINNESOTA CHAMBER OF COMMERCE	150.00	2/28/2018	355774	SESSION PRIORITIES 2/20/18	SP18-012018-	1/30/2018	LEKSON
376	84560	Community Events	3226	US BANK	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	3/1/2018	PITTMAN
377	84560	Community Events	3226	US BANK	25.00	2/28/2018	2009476	CC Recap-Cherry A. Jordan	2/2018-CAJ	3/1/2018	DEYOE
378	84560	Community Events	3226	US BANK	50.00	2/28/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	SCHREINER
379	84560	Community Events	3226	US BANK	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	SCHREINER
380	84560	Community Events	3226	US BANK	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	VAN
381	84560	Community Events	3226	US BANK	25.00	3/31/2018	2009481	CC Recap-Cherry A. Jordan	3/2018-CAJ	3/29/2018	DANNER
382	84560	Community Events	3226	US BANK	99.12	3/31/2018	2009481	CC Recap-Julie A. Simonsen	3/2018-JAS	3/29/2018	DEYOE
383	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	5/8/2018	DEYOE
384	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	5/8/2018	SCHREINER
385	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	5/8/2018	PTRAPP
386	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	5/8/2018	PITTMAN
387	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	200.00	4/30/2018	357860	GALA TABLE SPONSOR/TKT	21798	5/8/2018	VAN
388	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	100.00	4/30/2018	357688	2/20 EVENT-DEYOE/PITTMAN	30124	5/3/2018	DEYOE
389	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	100.00	4/30/2018	357688	2/20 EVENT-DEYOE/PITTMAN	30124	5/3/2018	PITTMAN
390	84560	Community Events	3226	US BANK	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	DEYOE
391	84560	Community Events	3226	US BANK	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	PITTMAN
392	84560	Community Events	3226	US BANK	118.71	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	SCHREINER
393	84560	Community Events	3226	US BANK	118.72	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	SHELDON
394	84560	Community Events	3226	US BANK	118.72	4/30/2018	2009476	CC Recap-Julie A. Simonsen	2/2018-JAS	3/1/2018	LEKSON
395	84560	Community Events	875	APPLE VALLEY CHAMBER OF COMM	20.00	5/31/2018	358564	STATE OF THE CITY 5/23/18	21861	6/7/2018	PITTMAN
396	84560	Community Events	3226	US BANK	25.00	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	VAN
397	84560	Community Events	3226	US BANK	40.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	LEKSON
398	84560	Community Events	3226	US BANK	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	DEYOE
399	84560	Community Events	3226	US BANK	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	PITTMAN
400	84560	Community Events	3226	US BANK	80.00	5/31/2018	2009490	CC Recap -Julie A. Simonsen	5/2018-JAS	5/31/2018	SCHREINER
401	84560	Community Events	3226	US BANK	165.00	5/31/2018	2009490	CC Recap-Cherry A. Jordan	5/2018-CAJ	5/31/2018	VAN
402	84560	Community Events	3226	US BANK	166.66	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	HOLTON
403	84560	Community Events	3226	US BANK	166.67	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	DEYOE
404	84560	Community Events	3226	US BANK	166.67	7/31/2018	2009486	CC Recap-Cherry A. Jordan	4/2018-CAJ	4/30/2018	JONES
405	84560	Community Events	3226	US BANK	53.74	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	LEKSON
406	84560	Community Events	3226	US BANK	53.74	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	LEKSON
407	84560	Community Events	3226	US BANK	107.48	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	DEYOE
408	84560	Community Events	3226	US BANK	107.48	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	SCHREINER
409	84560	Community Events	3226	US BANK	110.00	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BAKKEN
410	84560	Community Events	3226	US BANK	110.00	9/30/2018	2009512	CC Recap-Cherry A. Jordan	9/2018-CAJ	10/1/2018	BAKKEN
411	84560	Community Events	3226	US BANK	25.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	SCHREINER
412	84560	Community Events	3226	US BANK	35.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	LEKSON
413	84560	Community Events	3226	US BANK	70.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	SHELDON
414	84560	Community Events	3226	US BANK	75.00	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	SCHREINER
415	84560	Community Events	3226	US BANK	99.92	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	DEYOE
416	84560	Community Events	3226	US BANK	99.92	11/30/2018	2009526	CC Recap-Cherry A. Jordan	11/2018-CAJ	11/30/2018	VAN
417	84560	Community Events	3226	US BANK	150.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	DEYOE
418	84560	Community Events	3226	US BANK	150.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	LEKSON
419	84560	Community Events	3226	US BANK	225.00	11/30/2018	2009520	CC Recap-Cherry A. Jordan	10/2018-CAJ	10/31/2018	DEYOE
420	84560	Community Events	3226	US BANK	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	PITTMAN
421	84560	Community Events	3226	US BANK	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	DEYOE
422	84560	Community Events	3226	US BANK	300.00	11/30/2018	2009526	CC Recap-Julie A Simonsen	11/2018-JAS	11/30/2018	SCHREINER
423	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	1/17/2019	VAN
424	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	1/17/2019	JONES
425	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	1/17/2019	LEKSON
426	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	1/17/2019	SCHREINER
427	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	30.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/12	30861	1/17/2019	PITTMAN
428	84560	Community Events	653	LAKEVILLE AREA CHAMBER OF COMM	60.00	12/31/2018	364857	HOLIDAY LUNCHEON 12/13	30887	1/17/2019	DEYOE

Board of Directors Expenses

Line	Account #	Account Name	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT	Description	Invoice	Check Date	Project
429	84560	Community Events	3226	US BANK	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	LEKSON
430	84560	Community Events	3226	US BANK	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	SCHREINER
431	84560	Community Events	3226	US BANK	150.00	12/31/2018	2009534	CC Recap-Margaret (Peggy) P Jo	12/2018-PPJ	12/31/2018	VAN
				Total Community Events	**$ 6,657.47**						
432	84590	Other Travel Expense	2305	GERALD F PITTMAN JR	10.25	2/28/2018	2953	EXPENSE REPORT	FEB/2018	2/28/2018	PITTMAN
433	84590	Other Travel Expense	2625	JANET L LEKSON	122.68	2/28/2018	2952	EXPENSE REPORT	FEB/2018	2/28/2018	LEKSON
434	84590	Other Travel Expense	8207	JOHN D DEYOE	11.00	2/28/2018	2945	EXPENSE REPORT	FEB/2018	2/28/2018	DEYOE
435	84590	Other Travel Expense	3048	MARGARET D SCHREINER	5.00	2/28/2018	2955	EXPENSE REPORT	FEB/2018	2/28/2018	SCHREINER
436	84590	Other Travel Expense	3226	US BANK	165.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	PTRAPP
437	84590	Other Travel Expense	3226	US BANK	110.00	2/28/2018	2009467	CC Recap-Cherry Jordan	12/2017-CAJ	12/29/2017	DEYOE
438	84590	Other Travel Expense	2305	GERALD F PITTMAN JR	10.00	3/31/2018	2993	EXPENSE REPORT	MAR/2018	3/28/2018	PITTMAN
439	84590	Other Travel Expense	8207	JOHN D DEYOE	10.00	3/31/2018	2983	EXPENSE REPORT	MAR/2018	3/28/2018	DEYOE
440	84590	Other Travel Expense	3048	MARGARET D SCHREINER	11.00	3/31/2018	2994	EXPENSE REPORT	MAR/2018	3/28/2018	SCHREINER
441	84590	Other Travel Expense	5426	PAUL A TRAPP	118.00	3/31/2018	2996	EXPENSE REPORT	MAR/2018	3/28/2018	PTRAPP
442	84590	Other Travel Expense	2625	JANET L LEKSON	88.47	4/30/2018	3034	EXPENSE REPORT	APR/2018	5/1/2018	LEKSON
443	84590	Other Travel Expense	8207	JOHN D DEYOE	72.90	4/30/2018	3028	EXPENSE REPORT	APR/2018	5/1/2018	DEYOE
444	84590	Other Travel Expense	5426	PAUL A TRAPP	7.13	4/30/2018	3039	EXPENSE REPORT	APR/2018	5/1/2018	PTRAPP
445	84590	Other Travel Expense	3227	JUDITH H KIMMES	2.00	8/31/2018	3175	EXPENSE REPORT	AUG/2018	9/4/2018	KIMMES
446	84590	Other Travel Expense	8060	DAVID S JONES	15.00	9/30/2018	3209	EXPENSE REPORT	SEPT/2018	10/3/2018	JONES
447	84590	Other Travel Expense	2625	JANET L LEKSON	40.47	9/30/2018	3212	EXPENSE REPORT	SEPT/2018	10/3/2018	LEKSON
448	84590	Other Travel Expense	5426	PAUL A TRAPP	28.00	9/30/2018	3216	EXPENSE REPORT	SEPT/2018	10/3/2018	PTRAPP
449	84590	Other Travel Expense	8060	DAVID S JONES	54.17	11/30/2018	3279	EXPENSE REPORT	NOV/2018	12/7/2018	JONES
450	84590	Other Travel Expense	2305	GERALD F PITTMAN JR	9.75	11/30/2018	3284	EXPENSE REPORT	NOV/2018	12/7/2018	PITTMAN
451	84590	Other Travel Expense	3048	MARGARET D SCHREINER	377.84	11/30/2018	3285	EXPENSE REPORT	NOV/2018	12/7/2018	SCHREINER
452	84590	Other Travel Expense	8060	DAVID S JONES	5.00	12/31/2018	3306	EXPENSE REPORT	DEC/2018	12/28/2018	JONES
				Total BOD Other Travel	**$ 1,273.66**						
				Total Board of Directors Expense	**$ 419,222.79**						

Workpaper 15F
Top Ten Compensation

Dakota Electric Association
Highest 10 Compensated Employees
2018

	Employee Name	Salary	Short Term Incentive	Salary + Short Term Incentive	Benefits [1]	Grand Total
1	Greg Miller	$ 386,676	$ -	$ 386,676	$ 141,113	$ 527,789
2	Lou Ann Weflen	$ 222,068	$ 3,000	$ 225,068	$ 83,512	$ 308,580
3	Douglas Larson	$ 217,923	$ 3,000	$ 220,923	$ 77,020	$ 297,943
4	Michael Fosse	$ 201,096	$ 3,000	$ 204,096	$ 82,441	$ 286,537
5	Randall Poulson	$ 192,923	$ 3,000	$ 195,923	$ 69,439	$ 265,362
6	Dirk Rotty [2]	$ 82,346	$ 3,000	$ 85,346	$ 170,263	$ 255,609
7	Michael Nelson	$ 186,969	$ 3,000	$ 189,969	$ 32,779	$ 222,748
8	Craig Turner	$ 143,719	$ 8,000	$ 151,719	$ 49,164	$ 200,883
9	Grant Baumberger	$ 139,746	$ -	$ 139,746	$ 48,268	$ 188,014
10	Jeffrey Schoenecker [3]	$ 147,692	$ 1,500	$ 149,192	$ 24,566	$ 173,758
	Total	$ 1,921,158	$ 27,500	$ 1,948,658	$ 778,565	$ 2,727,223

[1] Benefits may include company paid medical, dental, 401k, pension, disability, auto, sick and vacation cash outs, and other benefits.
[2] Retired in June 2018.
[3] Promoted to Vice President in June 2018.

Workpaper 15G
Top Ten Expenses

Totp Ten Employees - Expenses

Line	Employee	Expense Type	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Business Purpose	Invoice	Check Date	Project
1	CRAIG TURNER	Dues & Memberships	3226	US BANK	291.00	1/31/2018	2009461	CC Recap-Craig C Turner	IEEE Annual Membership	11/2017-CCT	11/29/2017	EDU
2	JEFFREY SCHOENECKER	Dues & Memberships	3226	US BANK	291.00	1/31/2018	2009461	CC Recap-Jeffrey L Schoenecker	IEEE Annual Membership	11/2017-JLS	11/29/2017	ETS
3	CRAIG TURNER	Mileage	4042	CRAIG TURNER	46.87	1/31/2018	356007	EXPENSE REPORT	DistribuTech	JAN/2018	2/8/2018	EDU
4	JEFFREY SCHOENECKER	Mileage	6936	JEFFERY L SCHOENECKER	69.76	1/31/2018	2924	EXPENSE REPORT	Metro Coop Meeting	JAN/2018	2/2/2018	ETS
5	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*48.63*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*AGI*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
6	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*29.60*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*AGI*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
7	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*11.99*	*1/31/2018*	*2009471*	*CC Recap-Craig C. Turner*	*AGI*	*1/2018-CCT*	*1/30/2018*	*AGI2018*
8	CRAIG TURNER	Meals	4042	US BANK	8.00	1/31/2018	356007	EXPENSE REPORT	DistribuTech Conference	JAN/2018	2/8/2018	EDU
9	GREG MILLER	Meals	3226	US BANK	57.12	1/31/2018	2009471	CC Recap-Greg C. Miller	Dept holiday lunch	1/2018-GCM	1/30/2018	AMS
10	GREG MILLER	Meals	3226	US BANK	69.82	1/31/2018	2009471	CC Recap-Greg C. Miller	Dept holiday lunch	1/2018-GCM	1/30/2018	AMS
11	GREG MILLER	Meals	3226	US BANK	71.42	1/31/2018	2009471	CC Recap-Greg C. Miller	Board Meeting prep w board chair	1/2018-GCM	1/30/2018	AMS
12	GREG MILLER	Meals	3226	US BANK	338.00	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
13	GREG MILLER	Meals	3226	US BANK	61.34	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
14	GREG MILLER	Meals	3226	US BANK	6.95	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
15	GREG MILLER	Meals	3226	US BANK	51.66	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
16	GREG MILLER	Meals	3226	US BANK	145.01	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
17	MICHAEL FOSSE	Meals	3226	US BANK	31.67	1/31/2018	2009471	CC Recap-Michael G. Fosse	Planning meeting w/ M Nelson	1/2018-MGF	1/30/2018	ACS
18	CRAIG TURNER	Lodging	4042	CRAIG TURNER	1,342.88	1/31/2018	356007	EXPENSE REPORT	DistribuTech Conference (2 people 5 nights)	JAN/2018	2/8/2018	EDU
19	GREG MILLER	Lodging	3226	US BANK	1,230.64	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
20	GREG MILLER	Other Travel	3838	MILLER, GREG C	108.25	1/31/2018	355773	EXPENSE REPORT	NRECA	JAN/2018-EX	1/30/2018	AMS
21	CRAIG TURNER	Other Travel	4042	CRAIG TURNER	30.00	1/31/2018	356007	EXPENSE REPORT	DistribuTech Conference	JAN/2018	2/8/2018	EDU
22	GREG MILLER	Other Travel	3226	US BANK	49.20	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
23	GREG MILLER	Other Travel	3226	US BANK	53.40	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
24	GREG MILLER	Other Travel	3226	US BANK	61.38	1/31/2018	2009471	CC Recap-Greg C. Miller	NRECA	1/2018-GCM	1/30/2018	AMS
25	LOU ANN WEFLEN	Other Travel	3226	US BANK	3.00	1/31/2018	2009471	CC Recap-Lou Ann D. Weflen	MRET Meeting	1/2018-LAW	1/30/2018	WCOMP
26	MICHAEL FOSSE	Cell Phone	361		40.00	1/31/2018	229311	PAYROLL			1/11/2018	ACS
27	RANDALL POULSON	Cell Phone	232		40.00	1/31/2018	229349	PAYROLL			1/11/2018	AEN
28	CRAIG TURNER	Cell Phone	591		40.00	1/31/2018	229353	PAYROLL			1/11/2018	ETS
29	JEFFREY SCHOENECKER	Cell Phone	735		40.00	1/31/2018	229351	PAYROLL			1/11/2018	ETS
30	DOUGLAS LARSON	Cell Phone	753		40.00	1/31/2018	229359	PAYROLL			1/11/2018	AMS
31	DIRK ROTTY	Cell Phone	192		40.00	1/31/2018	229372	PAYROLL			1/11/2018	AUO
32	MICHAEL FOSSE	Airfare	3226	US BANK	474.60	2/28/2018	2009476	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	2/2018-MGF	3/1/2018	ACS
33	JEFFREY SCHOENECKER	Mileage	6936	JEFFERY L SCHOENECKER	25.07	2/28/2018	2954	EXPENSE REPORT	STEM Career Fair ISD 196	FEB/2015	2/28/2018	ETS
34	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*46.06*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*AGi*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
35	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*51.50*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*AGI*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
36	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*28.96*	*2/28/2018*	*2009476*	*CC Recap-Craig C. Turner*	*AGi*	*2/2018-CCT*	*3/1/2018*	*AGI2018*
37	CRAIG TURNER	Meals	3226	US BANK	5.74	2/28/2018	2009476	CC Recap-Craig C. Turner	DistribuTech Conference	2/2018-CCT	3/1/2018	EDU
38	CRAIG TURNER	Meals	3226	US BANK	20.00	2/28/2018	2009476	CC Recap-Craig C. Turner	DistribuTech Conference	2/2018-CCT	3/1/2018	EDU
39	CRAIG TURNER	Meals	3226	US BANK	20.00	2/28/2018	2009476	CC Recap-Craig C. Turner	DistribuTech Conference	2/2018-CCT	3/1/2018	EDU
40	CRAIG TURNER	Meals	3226	US BANK	39.60	2/28/2018	2009476	CC Recap-Craig C. Turner	DistribuTech Conference	2/2018-CCT	3/1/2018	EDU
41	GRANT BAUMBERGER	Meals	3226	US BANK	35.01	2/28/2018	2009476	CC Recap-Grant S. Baumberger	MVEC Substations	2/2018-GSB	3/1/2018	SUBO
42	GRANT BAUMBERGER	Meals	3226	US BANK	45.00	2/28/2018	2009476	CC Recap-Grant S. Baumberger	UMMA	2/2018-GSB	3/1/2018	EDU
43	GREG MILLER	Meals	3226	US BANK	83.07	2/28/2018	2009476	CC Recap-Greg C. Miller	Board Meeting prep w board chair	2/2018-GCM	3/1/2018	AMS
44	GREG MILLER	Meals	3226	US BANK	28.79	2/28/2018	2009476	CC Recap-Greg C. Miller	Annual physical	2/2018-GCM	3/1/2018	AMS
45	MICHAEL NELSON	Meals	3226	US BANK	31.00	2/28/2018	2009476	CC Recap-Michael R. Nelson	Employee recruitment	2/2018-MRN	3/1/2018	HIRE
46	RANDALL POULSON	Meals	3226	US BANK	21.86	2/28/2018	2009476	CC Recap-Randall Poulson	Key Account meeting	2/2018-RLP	3/1/2018	KEY
47	GREG MILLER	Lodging	3226	US BANK	153.63	2/28/2018	2009476	CC Recap-Greg C. Miller	GRE Mtg	2/2018-GCM	3/1/2018	AMS
48	GREG MILLER	Lodging	3226	US BANK	99.50	2/28/2018	2009476	CC Recap-Greg C. Miller	Annual physical	2/2018-GCM	3/1/2018	AMS
49	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	24.00	2/28/2018	2961	EXPENSE REPORT	PUC Planning; DOC Stakeholder; PUC DG	FEB/2018	3/7/2018	REG
50	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	11.00	2/28/2018	2961	EXPENSE REPORT	MN Chamber Session Priorities	FEB/2018	3/7/2018	LEGIS
51	CRAIG TURNER	Other Travel	3226	US BANK	120.00	2/28/2018	2009476	CC Recap-Craig C. Turner	DistribuTech Conference	2/2018-CCT	3/1/2018	EDU
52	MICHAEL FOSSE	Other Travel	3226	US BANK	36.41	2/28/2018	2009476	CC Recap-Michael G. Fosse		2/2018-MGF	3/1/2018	ACS
53	MICHAEL FOSSE	Cell Phone	361		40.00	2/28/2018	229891	PAYROLL			2/22/2018	ACS
54	RANDALL POULSON	Cell Phone	232		40.00	2/28/2018	229929	PAYROLL			2/22/2018	AEN
55	CRAIG TURNER	Cell Phone	591		40.00	2/28/2018	229933	PAYROLL			2/22/2018	ETS
56	JEFFREY SCHOENECKER	Cell Phone	735		40.00	2/28/2018	229931	PAYROLL			2/22/2018	ETS
57	DOUGLAS LARSON	Cell Phone	753		40.00	2/28/2018	229939	PAYROLL			2/22/2018	AMS
58	DIRK ROTTY	Cell Phone	192		40.00	2/28/2018	229951	PAYROLL			2/22/2018	AUO
59	MICHAEL FOSSE	Airfare	3226	US BANK	25.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	3/2018-MGF	3/29/2018	ACS
60	MICHAEL FOSSE	Airfare	3226	US BANK	25.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	3/2018-MGF	3/29/2018	ACS
61	JEFFREY SCHOENECKER	Mileage	6936	JEFFERY L SCHOENECKER	320.46	3/31/2018	2974	EXPENSE REPORT	NC Eng Conf; IEEE 1547 Seminar	MAR/2018	3/16/2018	EDU
62	CRAIG TURNER	Meals	3226	US BANK	32.97	3/31/2018	2009481	CC Recap-Craig C. Turner	North Central Engineering Conference	3/2018-CCT	3/29/2018	EDU
63	*GRANT BAUMBERGER*	*Meals*	*3226*	*US BANK*	*41.00*	*3/31/2018*	*2009481*	*CC Recap-Grant S. Baumberger*	*AGi*	*3/2018-GSB*	*3/29/2018*	*AGI2018*
64	GRANT BAUMBERGER	Meals	3226	US BANK	51.00	3/31/2018	2009481	CC Recap-Grant S. Baumberger	UMMA	3/2018-GSB	3/29/2018	EDU
65	GREG MILLER	Meals	3226	US BANK	40.74	3/31/2018	2009481	CC Recap-Greg C. Miller	Board Meeting prep w board chair	3/2018-GCM	3/29/2018	AMS
66	GREG MILLER	Meals	3226	US BANK	37.60	3/31/2018	2009481	CC Recap-Greg C. Miller	DCTC meeting	3/2018-GCM	3/29/2018	AMS
67	GREG MILLER	Meals	3226	US BANK	80.89	3/31/2018	2009481	CC Recap-Greg C. Miller	Connexus meeting	3/2018-GCM	3/29/2018	AMS
68	GREG MILLER	Meals	3226	US BANK	78.26	3/31/2018	2009481	CC Recap-Greg C. Miller	Itineris meeting (CIS)	3/2018-GCM	3/29/2018	AMS
69	JEFFREY SCHOENECKER	Meals	3226	US BANK	25.42	3/31/2018	2009481	CC Recap-Jeffrey L. Schoenecke	STEM Career Fair ISD 196 (2)	3/2018-JLS	3/29/2018	ETS
70	MICHAEL FOSSE	Meals	3226	US BANK	6.74	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	3/2018-MGF	3/29/2018	ACS
71	MICHAEL FOSSE	Meals	3226	US BANK	35.96	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	3/2018-MGF	3/29/2018	ACS

Line	Employee	Expense Type	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Business Purpose	Invoice	Check Date	Project
72	MICHAEL FOSSE	Meals	3226	US BANK	27.99	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	3/2018-MGF	3/29/2018	ACS
73	MICHAEL NELSON	Meals	3226	US BANK	65.00	3/31/2018	2009481	CC Recap-Michael R. Nelson	Staff Overtime work (appreciation)	3/2018-MRN	3/29/2018	IFS
74	CRAIG TURNER	Lodging	3226	US BANK	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	North Central Engineering Conf (Turner)	3/2018-CCT	3/29/2018	EDU
75	CRAIG TURNER	Lodging	3226	US BANK	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	North Central Engineering Conf (Schoenecker)	3/2018-CCT	3/29/2018	EDU
76	CRAIG TURNER	Lodging	3226	US BANK	213.18	3/31/2018	2009481	CC Recap-Craig C. Turner	North Central Engineering Conf (Peterson)	3/2018-CCT	3/29/2018	EDU
77	GREG MILLER	Lodging	3226	US BANK	115.31	3/31/2018	2009481	CC Recap-Greg C. Miller	GRE Regional Mtg.	3/2018-GCM	3/29/2018	AMS
78	MICHAEL FOSSE	Lodging	3226	US BANK	638.88	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	3/2018-MGF	3/29/2018	ACS
79	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	18.00	3/31/2018	3001	EXPENSE REPORT	PUC Mtg; PUC EV Workshop	MAR/2018	4/4/2018	REG
80	DOUGLAS LARSON	Other Travel	3226	US BANK	35.00	3/31/2018	2009481	CC Recap-Douglas R. Larson	Xcel meeting	3/2018-DRL	3/29/2018	REG
81	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	8.00	3/31/2018	2009481	CC Recap-Jeffrey L. Schoenecke		3/2018-JLS	3/29/2018	ETS
82	MICHAEL FOSSE	Other Travel	3226	US BANK	11.00	3/31/2018	2009481	CC Recap-Michael G. Fosse	Miscoded - Other Vehicle	3/2018-MGF	3/29/2018	ACS
83	MICHAEL FOSSE	Other Travel	3226	US BANK	42.85	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	3/2018-MGF	3/29/2018	ACS
84	MICHAEL FOSSE	Other Travel	3226	US BANK	32.50	3/31/2018	2009481	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	3/2018-MGF	3/29/2018	ACS
85	MICHAEL FOSSE	Cell Phone	361		12.00	3/31/2018	230085	PAYROLL			2/28/2018	ACS
86	MICHAEL FOSSE	Cell Phone	361		28.00	3/31/2018	230085	PAYROLL			3/8/2018	ACS
87	RANDALL POULSON	Cell Phone	232		12.00	3/31/2018	230123	PAYROLL			2/28/2018	AEN
88	RANDALL POULSON	Cell Phone	232		28.00	3/31/2018	230123	PAYROLL			3/8/2018	AEN
89	CRAIG TURNER	Cell Phone	591		12.00	3/31/2018	230127	PAYROLL			2/28/2018	ETS
90	CRAIG TURNER	Cell Phone	591		28.00	3/31/2018	230127	PAYROLL			3/8/2018	ETS
91	JEFFREY SCHOENECKER	Cell Phone	735		12.00	3/31/2018	230125	PAYROLL			2/28/2018	ETS
92	JEFFREY SCHOENECKER	Cell Phone	735		28.00	3/31/2018	230125	PAYROLL			3/8/2018	ETS
93	DOUGLAS LARSON	Cell Phone	753		12.00	3/31/2018	230133	PAYROLL			2/28/2018	AMS
94	DOUGLAS LARSON	Cell Phone	753		28.00	3/31/2018	230133	PAYROLL			3/8/2018	AMS
95	DIRK ROTTY	Cell Phone	192		12.00	3/31/2018	230146	PAYROLL			2/28/2018	AUO
96	DIRK ROTTY	Cell Phone	192		28.00	3/31/2018	230146	PAYROLL			3/8/2018	AUO
97	JEFFREY SCHOENECKER	Airfare	3226	US BANK	256.60	4/30/2018	2009471	CC Recap-Jeffrey L. Schoenecke	IEEE Conference	1/2018-JLS	1/30/2018	EDU
98	CRAIG TURNER	Mileage	4042	CRAIG TURNER	110.64	4/30/2018	358013	EXPENSE REPORT	e21 Presentation; Steffes WH; PUC	APR-19-18	5/15/2018	ETS
99	JEFFREY SCHOENECKER	Mileage	6936	JEFFERY L SCHOENECKER	42.51	4/30/2018	3036	EXPENSE REPORT	IEEE T&D	APR/2018	5/1/2018	EDU
100	DOUGLAS LARSON	Meals	3226	US BANK	71.56	4/30/2018	2009486	CC Recap-Douglas R. Larson	MREA Annual Mtg (4)	4/2018-DRL	4/30/2018	LEGIS
101	GREG MILLER	Meals	3226	US BANK	47.76	4/30/2018	2009486	CC Recap-Greg C. Miller	GRE Bd Bk review with DEA directors (4)	4/2018-GCM	4/30/2018	AMS
102	MICHAEL FOSSE	Meals	3226	US BANK	55.96	4/30/2018	2009486	CC Recap-Michael G. Fosse	Website Contingency & Long Range Planning (3)	4/2018-MGF	4/30/2018	WEBSITE
103	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	7.50	4/30/2018	3046	EXPENSE REPORT	PUC Meeting	APR/2018	5/9/2018	REG
104	DOUGLAS LARSON	Other Travel	3226	US BANK	8.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	Legislative meeting	4/2018-DRL	4/30/2018	LEGIS
105	DOUGLAS LARSON	Other Travel	3226	US BANK	13.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	Legislative meeting	4/2018-DRL	4/30/2018	LEGIS
106	DOUGLAS LARSON	Other Travel	3226	US BANK	6.00	4/30/2018	2009486	CC Recap-Douglas R. Larson	MREA Legislative Reception	4/2018-DRL	4/30/2018	LEGIS
107	GREG MILLER	Other Travel	3226	US BANK	10.00	4/30/2018	2009486	CC Recap-Greg C. Miller	MREA Mtg	4/2018-GCM	4/30/2018	AMS
108	GREG MILLER	Other Travel	3226	US BANK	11.00	4/30/2018	2009486	CC Recap-Greg C. Miller	MREA Mtg	4/2018-GCM	4/30/2018	AMS
109	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	52.50	4/30/2018	2009486	CC Recap-Jeffrey L. Schoenecke	IEEE Conference	4/2018-JLS	4/30/2018	EDU
110	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	51.92	4/30/2018	2009486	CC Recap-Jeffrey L. Schoenecke	IEEE Conference	4/2018-JLS	4/30/2018	EDU
111	MICHAEL FOSSE	Cell Phone	361		20.00	4/30/2018	230471	PAYROLL			3/31/2018	ACS
112	MICHAEL FOSSE	Cell Phone	361		20.00	4/30/2018	230471	PAYROLL			4/5/2018	ACS
113	RANDALL POULSON	Cell Phone	232		20.00	4/30/2018	230509	PAYROLL			3/31/2018	AEN
114	RANDALL POULSON	Cell Phone	232		20.00	4/30/2018	230509	PAYROLL			4/5/2018	AEN
115	CRAIG TURNER	Cell Phone	591		20.00	4/30/2018	230513	PAYROLL			3/31/2018	ETS
116	CRAIG TURNER	Cell Phone	591		20.00	4/30/2018	230513	PAYROLL			4/5/2018	ETS
117	JEFFREY SCHOENECKER	Cell Phone	735		20.00	4/30/2018	230511	PAYROLL			3/31/2018	ETS
118	JEFFREY SCHOENECKER	Cell Phone	735		20.00	4/30/2018	230511	PAYROLL			4/5/2018	ETS
119	DOUGLAS LARSON	Cell Phone	753		20.00	4/30/2018	230519	PAYROLL			3/31/2018	AMS
120	DOUGLAS LARSON	Cell Phone	753		20.00	4/30/2018	230519	PAYROLL			4/5/2018	AMS
121	DIRK ROTTY	Cell Phone	192		20.00	4/30/2018	230532	PAYROLL			3/31/2018	AUO
122	DIRK ROTTY	Cell Phone	192		20.00	4/30/2018	230532	PAYROLL			4/5/2018	AUO
123	CRAIG TURNER	Dues & Memberships	3226	US BANK	384.00	5/31/2018	2009490	CC Recap-Craig C. Turner	Annual Professional Engineering Society	5/2018-CCT	5/31/2018	ETS
124	CRAIG TURNER	Meals	3226	US BANK	13.69	5/31/2018	2009490	CC Recap-Craig C. Turner	PUC Meeting (2)	5/2018-CCT	5/31/2018	REGENGINEER
125	DOUGLAS LARSON	Meals	3226	US BANK	55.10	5/31/2018	2009490	CC Recap-Douglas R. Larson	PUC Meeting (6)	5/2018-DRL	5/31/2018	REG
126	DOUGLAS LARSON	Meals	3226	US BANK	48.99	5/31/2018	2009490	CC Recap-Douglas R. Larson	PUC DG Advisory Group Meeting (2)	5/2018-DRL	5/31/2018	REG
127	GREG MILLER	Meals	3226	US BANK	71.42	5/31/2018	2009490	CC Recap-Greg C. Miller	Board Meeting prep w board chair	5/2018-GCM	5/31/2018	AMS
128	GREG MILLER	Meals	3226	US BANK	86.77	5/31/2018	2009490	CC Recap-Greg C. Miller	Admin Day lunch (4)	5/2018-GCM	5/31/2018	AMS
129	GREG MILLER	Meals	3226	US BANK	61.88	5/31/2018	2009490	CC Recap-Greg C. Miller	Meet with Key Account (3)	5/2018-GCM	5/31/2018	AMS
130	GREG MILLER	Meals	3226	US BANK	56.71	5/31/2018	2009490	CC Recap-Greg C. Miller	GRE Bd Mtg prep with DEA directors (4)	5/2018-GCM	5/31/2018	AMS
131	JEFFREY SCHOENECKER	Meals	3226	US BANK	4.05	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
132	JEFFREY SCHOENECKER	Meals	3226	US BANK	12.09	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
133	JEFFREY SCHOENECKER	Meals	3226	US BANK	16.03	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
134	JEFFREY SCHOENECKER	Meals	3226	US BANK	15.12	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
135	JEFFREY SCHOENECKER	Meals	3226	US BANK	12.96	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
136	JEFFREY SCHOENECKER	Meals	3226	US BANK	7.27	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
137	JEFFREY SCHOENECKER	Meals	3226	US BANK	7.53	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Meeting	5/2018-JLS	5/31/2018	EDU
138	JEFFREY SCHOENECKER	Meals	3226	US BANK	74.45	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	ETS section lunch to discuss goals (5)	5/2018-JLS	5/31/2018	ETS
139	JEFFREY SCHOENECKER	Meals	3226	US BANK	25.43	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	Annual performance discussion (2)	5/2018-JLS	5/31/2018	ETS
140	MICHAEL FOSSE	Meals	3226	US BANK	38.63	5/31/2018	2009490	CC Recap-Michael G. Fosse	Call Center planning (3)	5/2018-MGF	5/31/2018	CUS
141	*GRANT BAUMBERGER*	*Lodging*	*3226*	*US BANK*	*623.92*	*5/31/2018*	*2009486*	*CC Recap-Grant S. Baumberger*	*AGi - Meter School (M. Nielson)*	*4/2018-GSB*	*4/30/2018*	*AGI2018*
142	JEFFREY SCHOENECKER	Lodging	3226	US BANK	725.76	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE T&D Conference	5/2018-JLS	5/31/2018	EDU
143	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	26.00	5/31/2018	3065	EXPENSE REPORT	PUC Mtg; PUC DG Advisory Group	MAY/2018	6/6/2018	REG
144	*CRAIG TURNER*	*Other Travel*	*3226*	*US BANK*	*11.00*	*5/31/2018*	*2009490*	*CC Recap-Craig C. Turner*	*PUC Meeting*	*5/2018-CCT*	*5/31/2018*	*AGI2018*

Line	Employee	Expense Type	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Business Purpose	Invoice	Check Date	Project
145	CRAIG TURNER	Other Travel	3226	US BANK	8.00	5/31/2018	2009490	CC Recap-Craig C. Turner	PUC Meeting	5/2018-CCT	5/31/2018	REGENGINEER
146	DOUGLAS LARSON	Other Travel	3226	US BANK	8.00	5/31/2018	2009490	CC Recap-Douglas R. Larson	U of M DER Listening Session	5/2018-DRL	5/31/2018	POWSUP
147	GREG MILLER	Other Travel	3226	US BANK	10.00	5/31/2018	2009490	CC Recap-Greg C. Miller	PUC Meeting	5/2018-GCM	5/31/2018	AMS
148	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	25.00	5/31/2018	2009490	CC Recap-Jeffrey L. Schoenecke	IEEE Conference	5/2018-JLS	5/31/2018	EDU
149	MICHAEL NELSON	Other Travel	3226	US BANK	7.50	5/31/2018	2009490	CC Recap-Michael R. Nelson	PUC Meeting	5/2018-MRN	5/31/2018	IFS
150	MICHAEL FOSSE	Cell Phone	361		24.00	5/31/2018	230857	PAYROLL			4/30/2018	ACS
151	MICHAEL FOSSE	Cell Phone	361		16.00	5/31/2018	230857	PAYROLL			5/3/2018	ACS
152	RANDALL POULSON	Cell Phone	232		24.00	5/31/2018	230895	PAYROLL			4/30/2018	AEN
153	RANDALL POULSON	Cell Phone	232		16.00	5/31/2018	230895	PAYROLL			5/3/2018	AEN
154	CRAIG TURNER	Cell Phone	591		24.00	5/31/2018	230899	PAYROLL			4/30/2018	ETS
155	CRAIG TURNER	Cell Phone	591		16.00	5/31/2018	230899	PAYROLL			5/3/2018	ETS
156	JEFFREY SCHOENECKER	Cell Phone	735		24.00	5/31/2018	230897	PAYROLL			4/30/2018	ETS
157	JEFFREY SCHOENECKER	Cell Phone	735		16.00	5/31/2018	230897	PAYROLL			5/3/2018	ETS
158	DOUGLAS LARSON	Cell Phone	753		24.00	5/31/2018	230905	PAYROLL			4/30/2018	AMS
159	DOUGLAS LARSON	Cell Phone	753		16.00	5/31/2018	230905	PAYROLL			5/3/2018	AMS
160	DIRK ROTTY	Cell Phone	192		24.00	5/31/2018	230918	PAYROLL			4/30/2018	AUO
161	DIRK ROTTY	Cell Phone	192		16.00	5/31/2018	230918	PAYROLL			5/3/2018	AUO
162	GRANT BAUMBERGER	Airfare	3226	US BANK	453.40	6/30/2018	2009490	CC Recap-Grant S. Baumberger	TESCO Users Group Mtg	5/2018-GSB	5/31/2018	EDU
163	DOUGLAS LARSON	Meals	3226	US BANK	78.42	6/30/2018	2009496	CC Recap-Douglas R. Larson	Solar RFP Meeting (6)	6/2018-DRL	7/2/2018	SOLAR
164	DOUGLAS LARSON	Meals	3226	US BANK	55.39	6/30/2018	2009496	CC Recap-Douglas R. Larson	PUC DG Interconnection Mtg (3)	6/2018-DRL	7/2/2018	REG
165	DOUGLAS LARSON	Meals	3226	US BANK	33.40	6/30/2018	2009496	CC Recap-Douglas R. Larson	Connexus meeting (GRE) (2)	6/2018-DRL	7/2/2018	POWSUP
166	GRANT BAUMBERGER	Meals	3226	US BANK	24.00	6/30/2018	2009496	CC Recap-Grant S. Baumberger	TESCO Meter Conference	6/2018-GSB	7/2/2018	EDU
167	GRANT BAUMBERGER	Meals	3226	US BANK	90.30	6/30/2018	2009496	CC Recap-Grant S. Baumberger	TESCO Meter Conference	6/2018-GSB	7/2/2018	EDU
168	GREG MILLER	Meals	3226	US BANK	23.28	6/30/2018	2009496	CC Recap-Greg C. Miller	Scholarships (2)	6/2018-GCM	7/2/2018	AMS
169	GREG MILLER	Meals	3226	US BANK	39.08	6/30/2018	2009496	CC Recap-Greg C. Miller	GRE Bd Mtg prep with DEA directors (4)	6/2018-GCM	7/2/2018	AMS
170	GREG MILLER	Meals	3226	US BANK	83.07	6/30/2018	2009496	CC Recap-Greg C. Miller	Board Meeting prep w board chair	6/2018-GCM	7/2/2018	AMS
171	GREG MILLER	Meals	3226	US BANK	446.41	6/30/2018	2009496	CC Recap-Greg C. Miller	VP Retirement recognition (6)	6/2018-GCM	7/2/2018	AMS
172	GREG MILLER	Meals	3226	US BANK	59.12	6/30/2018	2009496	CC Recap-Greg C. Miller	DCTC meeting (3)	6/2018-GCM	7/2/2018	AMS
173	GREG MILLER	Meals	3226	US BANK	43.35	6/30/2018	2009496	CC Recap-Greg C. Miller	Organization planning (2)	6/2018-GCM	7/2/2018	AMS
174	GREG MILLER	Meals	3226	US BANK	39.01	6/30/2018	2009496	CC Recap-Greg C. Miller	Board Meeting prep w board chair	6/2018-GCM	7/2/2018	AMS
175	GREG MILLER	Meals	3226	US BANK	55.26	6/30/2018	2009496	CC Recap-Greg C. Miller	Key Account meeting (3)	6/2018-GCM	7/2/2018	AMS
176	MICHAEL FOSSE	Meals	3226	US BANK	29.05	6/30/2018	2009496	CC Recap-Michael G. Fosse	Business Process meeting (2)	6/2018-MGF	7/2/2018	ACS
177	GRANT BAUMBERGER	Lodging	3226	US BANK	729.63	6/30/2018	2009496	CC Recap-Grant S. Baumberger	TESCO Meter Conference	6/2018-GSB	7/2/2018	EDU
178	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	13.00	6/30/2018	3111	EXPENSE REPORT	PUC - DG Advisory Group	JUNE/2018	7/11/2018	REG
179	CRAIG TURNER	Other Travel	3226	US BANK	8.00	6/30/2018	2009496	CC Recap-Craig C. Turner	PUC Meeting	6/2018-CCT	7/2/2018	REGENGINEER
180	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	8.50	6/30/2018	2009496	CC Recap-Jeffrey L. Schoenecke	PUC Meeting	6/2018-JLS	7/2/2018	ETS
181	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	39.25	6/30/2018	2009496	CC Recap-Jeffrey L. Schoenecke	Miscoded - Fuel	6/2018-JLS	7/2/2018	AUO
182	RANDALL POULSON	Cell Phone	232		40.00	6/30/2018	231500	PAYROLL			6/14/2018	AEN
183	CRAIG TURNER	Cell Phone	591		40.00	6/30/2018	231503	PAYROLL			6/14/2018	ETS
184	JEFFREY SCHOENECKER	Cell Phone	735		40.00	6/30/2018	231524	PAYROLL			6/14/2018	AUO
185	DOUGLAS LARSON	Cell Phone	753		40.00	6/30/2018	231509	PAYROLL			6/14/2018	AMS
186	CRAIG TURNER	Dues & Memberships	3226	US BANK	122.50	7/31/2018	2009496	CC Recap-Craig C. Turner	Minnesota Profession Engineering license	6/2018-CCT	7/2/2018	ETS
187	JEFFREY SCHOENECKER	Dues & Memberships	3226	US BANK	122.50	7/31/2018	2009496	CC Recap-Jeffrey L. Schoenecke	Minnesota Profession Engineering license	6/2018-JLS	7/2/2018	ETS
188	MICHAEL FOSSE	Airfare	3226	US BANK	542.40	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	7/2018-MGF	7/31/2018	ACS
189	MICHAEL FOSSE	Airfare	3226	US BANK	25.00	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	7/2018-MGF	7/31/2018	ACS
190	MICHAEL FOSSE	Airfare	3226	US BANK	25.00	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	7/2018-MGF	7/31/2018	ACS
191	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*22.45*	*7/31/2018*	*2009501*	*CC Recap-Craig C. Turner*	*AGi (2)*	*7/2018-CCT*	*7/31/2018*	*AGI2018*
192	DOUGLAS LARSON	Meals	3226	US BANK	29.23	7/31/2018	2009501	CC Recap-Douglas R. Larson	Meet with coop re: power supply (2)	7/2018-DRL	7/31/2018	POWSUP
193	GREG MILLER	Meals	3226	US BANK	41.23	7/31/2018	2009501	CC Recap-Greg C. Miller	Board Meeting prep w board chair	7/2018-GCM	7/31/2018	AMS
194	GREG MILLER	Meals	3226	US BANK	55.59	7/31/2018	2009501	CC Recap-Greg C. Miller	MREA Update (2)	7/2018-GCM	7/31/2018	AMS
195	JEFFREY SCHOENECKER	Meals	3226	US BANK	28.00	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	VP Transition (2)	7/2018-JLS	7/31/2018	AUO
196	JEFFREY SCHOENECKER	Meals	3226	US BANK	38.11	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	Solar Project meeting (3)	7/2018-JLS	7/31/2018	AUO
197	LOU ANN WEFLEN	Meals	3226	US BANK	63.51	7/31/2018	2009501	CC Recap-Lou Ann D. Weflen	Crew lunch (5)	7/2018-LAW	7/31/2018	AFS
198	MICHAEL FOSSE	Meals	3226	US BANK	33.46	7/31/2018	2009501	CC Recap-Michael G. Fosse	Meeting re: account metering (2)	7/2018-MGF	7/31/2018	ACS
199	MICHAEL FOSSE	Meals	3226	US BANK	23.17	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy Board Meeting	7/2018-MGF	7/31/2018	ACS
200	MICHAEL FOSSE	Meals	3226	US BANK	34.68	7/31/2018	2009501	CC Recap-Michael G. Fosse	Circuits design meeting (2)	7/2018-MGF	7/31/2018	CIRC2018
201	DOUGLAS LARSON	Lodging	3226	US BANK	70.12	7/31/2018	2009501	CC Recap-Douglas R. Larson	GRE MMG Mtg	7/2018-DRL	7/31/2018	POWSUP
202	DOUGLAS LARSON	Lodging	3226	US BANK	192.28	7/31/2018	2009501	CC Recap-Douglas R. Larson	GRE BOD & MMG Strategic Planning	7/2018-DRL	7/31/2018	POWSUP
203	GREG MILLER	Lodging	3226	US BANK	70.12	7/31/2018	2009501	CC Recap-Greg C. Miller	GRE MMG Mtg	7/2018-GCM	7/31/2018	AMS
204	GREG MILLER	Lodging	3226	US BANK	192.28	7/31/2018	2009501	CC Recap-Greg C. Miller	GRE BOD & MMG Strategic Planning	7/2018-GCM	7/31/2018	AMS
205	LOU ANN WEFLEN	Lodging	3226	US BANK	362.38	7/31/2018	2009490	CC Recap-Lou Ann D. Weflen	MRET ANNUAL MEETING	5/2018-LAW	5/31/2018	WCOMP
206	MICHAEL FOSSE	Lodging	3226	US BANK	528.76	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	7/2018-MGF	7/31/2018	ACS
207	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	12.00	7/31/2018	3147	EXPENSE REPORT	PUC - DG Advisory Group	JULY/2018	8/8/2018	REG
208	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	10.69	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	Miscoded - Other Vehicle	7/2018-JLS	7/31/2018	AUO
209	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	23.33	7/31/2018	2009501	CC Recap-Jeffrey L Schoenecker	Miscoded - Fuel	7/2018-JLS	7/31/2018	AUO
210	MICHAEL FOSSE	Other Travel	3226	US BANK	39.64	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	7/2018-MGF	7/31/2018	ACS
211	MICHAEL FOSSE	Other Travel	3226	US BANK	75.72	7/31/2018	2009501	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	7/2018-MGF	7/31/2018	ACS
212	RANDALL POULSON	Cell Phone	232		40.00	7/31/2018	231908	PAYROLL			7/31/2018	AEN
213	CRAIG TURNER	Cell Phone	591		40.00	7/31/2018	231911	PAYROLL			7/31/2018	ETS
214	JEFFREY SCHOENECKER	Cell Phone	735		40.00	7/31/2018	231931	PAYROLL			7/31/2018	AUO
215	DOUGLAS LARSON	Cell Phone	753		40.00	7/31/2018	231917	PAYROLL			7/31/2018	AMS
216	CRAIG TURNER	Meals	3226	US BANK	151.46	8/31/2018	2009507	CC Recap-Craig C. Turner	Milsoft Presentation (4)	8/2018-CCT	8/30/2018	ETS
217	*CRAIG TURNER*	*Meals*	*3226*	*US BANK*	*52.53*	*8/31/2018*	*2009507*	*CC Recap-Craig C. Turner*	*AGi Kickoff Meeting*	*8/2018-CCT*	*8/30/2018*	*AGI2018*

Line	Employee	Expense Type	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Business Purpose	Invoice	Check Date	Project
218	GREG MILLER	Meals	3226	US BANK	107.77	8/31/2018	2009507	CC Recap-Greg C. Miller	Strategic Planning Retreat (7)	8/2018-GCM	8/30/2018	AMS
219	GREG MILLER	Meals	3226	US BANK	28.63	8/31/2018	2009507	CC Recap-Greg C. Miller	Board Meeting prep w board chair	8/2018-GCM	8/30/2018	AMS
220	GREG MILLER	Meals	3226	US BANK	68.04	8/31/2018	2009507	CC Recap-Greg C. Miller	Board Planning (3)	8/2018-GCM	8/30/2018	AMS
221	GREG MILLER	Meals	3226	US BANK	44.21	8/31/2018	2009507	CC Recap-Greg C. Miller	Mtg with Connexus (2)	8/2018-GCM	8/30/2018	AMS
222	JEFFREY SCHOENECKER	Meals	3226	US BANK	6.41	8/31/2018	2009507	CC Recap-Jeffrey L Schoenecker	Member Appreciation Event	8/2018-JLS	8/30/2018	AUO
223	RANDALL POULSON	Meals	3226	US BANK	16.37	8/31/2018	2009507	CC Recap-Randall Poulson	New Engineer hiring (2)	8/2018-RLP	8/30/2018	ETS
224	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	35.12	8/31/2018	2009507	CC Recap-Jeffrey L Schoenecker	Miscoded -Fuel	8/2018-JLS	8/30/2018	AUO
225	RANDALL POULSON	Cell Phone	232		40.00	8/31/2018	232311	PAYROLL			8/9/2018	AEN
226	CRAIG TURNER	Cell Phone	591		40.00	8/31/2018	232314	PAYROLL			8/9/2018	ETS
227	JEFFREY SCHOENECKER	Cell Phone	735		40.00	8/31/2018	232334	PAYROLL			8/9/2018	AUO
228	DOUGLAS LARSON	Cell Phone	753		40.00	8/31/2018	232320	PAYROLL			8/9/2018	AMS
229	CRAIG TURNER	Airfare	4042	CRAIG TURNER	254.40	9/30/2018	361935	EXPENSE REPORT	Itron Users Group Mtg	SEP/2018	10/12/2018	AGI2018
230	GRANT BAUMBERGER	Airfare	3226	US BANK	179.40	9/30/2018	2009486	CC Recap-Grant S. Baumberger	Meter School (M. Nielson)	4/2018-GSB	4/30/2018	AGI2018
231	CRAIG TURNER	Mileage	4042	CRAIG TURNER	89.93	9/30/2018	361935	EXPENSE REPORT	Xcel IDP Stakeholders	SEP/2018	10/9/2018	REG
232	CRAIG TURNER	Mileage	4042	CRAIG TURNER	50.14	9/30/2018	361935	EXPENSE REPORT	PUC DG Working Group	SEP/2018	10/9/2018	REGENGINEER
233	CRAIG TURNER	Mileage	4042	CRAIG TURNER	24.53	9/30/2018	361935	EXPENSE REPORT	Itron Users Group	SEP/2018	10/9/2018	AGI2018
234	CRAIG TURNER	Meals	3226	US BANK	62.26	9/30/2018	2009512	CC Recap-Craig C. Turner	New employee intro to staff (4)	9/2018-CCT	10/1/2018	ETS
235	CRAIG TURNER	Meals	3226	US BANK	11.94	9/30/2018	2009512	CC Recap-Craig C. Turner	Mtg with Xcel	9/2018-CCT	10/1/2018	REG
236	CRAIG TURNER	Meals	4042	US BANK	6,230.00	9/30/2018	361935	EXPENSE REPORT		SEP/2018	10/9/2018	AGI2018
237	DOUGLAS LARSON	Meals	3226	US BANK	37.07	9/30/2018	2009512	CC Recap-Douglas R. Larson	Mtg with Xcel to discuss Byllesby Dam (2)	9/2018-DRL	10/1/2018	KEY
238	GRANT BAUMBERGER	Meals	3226	US BANK	133.98	9/30/2018	2009512	CC Recap-Grant S. Baumberger	ElecTech luncheon (8)	9/2018-GSB	10/1/2018	TEC
239	GREG MILLER	Meals	3226	US BANK	29.07	9/30/2018	2009512	CC Recap-Greg C. Miller	Board Meeting prep w board chair	9/2018-GCM	10/1/2018	AMS
240	JEFFREY SCHOENECKER	Meals	3226	US BANK	24.87	9/30/2018	2009512	CC Recap-Jeffrey L Schoenecker	Engineering responsibilities (2)	9/2018-JLS	10/1/2018	AUO
241	MICHAEL FOSSE	Meals	3226	US BANK	36.00	9/30/2018	2009512	CC Recap-Michael G. Fosse	Customer Service Planning (2)	9/2018-MGF	10/1/2018	ACS
242	CRAIG TURNER	Lodging	3226	US BANK	306.45	9/30/2018	2009512	CC Recap-Craig C. Turner	Itron User Group Meeting deposit	9/2018-CCT	10/1/2018	AGI2018
243	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	22.00	9/30/2018	3224	EXPENSE REPORT	PUC Mtgs; PUC DG Advisory Group	SEP/2018	10/12/2018	REG
244	CRAIG TURNER	Other Travel	3226	US BANK	13.00	9/30/2018	2009512	CC Recap-Craig C. Turner	Xcel IDP meeting	9/2018-CCT	10/1/2018	REG
245	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	40.44	9/30/2018	2009512	CC Recap-Jeffrey L Schoenecker	Miscoded -Fuel	9/2018-JLS	10/1/2018	AUO
246	RANDALL POULSON	Cell Phone	232		20.00	9/30/2018	232716	PAYROLL			8/31/2018	AEN
247	RANDALL POULSON	Cell Phone	232		20.00	9/30/2018	232716	PAYROLL			9/6/2018	AEN
248	CRAIG TURNER	Cell Phone	591		20.00	9/30/2018	232719	PAYROLL			8/31/2018	ETS
249	CRAIG TURNER	Cell Phone	591		20.00	9/30/2018	232719	PAYROLL			9/6/2018	ETS
250	JEFFREY SCHOENECKER	Cell Phone	735		20.00	9/30/2018	232739	PAYROLL			8/31/2018	AUO
251	JEFFREY SCHOENECKER	Cell Phone	735		20.00	9/30/2018	232739	PAYROLL			9/6/2018	AUO
252	DOUGLAS LARSON	Cell Phone	753		20.00	9/30/2018	232725	PAYROLL			8/31/2018	AMS
253	DOUGLAS LARSON	Cell Phone	753		20.00	9/30/2018	232725	PAYROLL			9/6/2018	AMS
254	JEFFREY SCHOENECKER	Dues & Memberships	3226	US BANK	299.00	10/31/2018	2009520	CC Recap-Jeffrey L Schoenecker	National Society of Professional Engineers	10/2018-JLS	10/31/2018	AUO
255	CRAIG TURNER	Mileage	4042	CRAIG TURNER	24.53	10/31/2018	361935	EXPENSE REPORT	Itron Users Group	OCT/2018	10/9/2018	AGI2018
256	CRAIG TURNER	Meals	3226	US BANK	38.29	10/31/2018	2009520	CC Recap-Craig C. Turner	GRE/CEE long range plan and IDP mtg (4)	10/2018-CCT	10/31/2018	ETS
257	GREG MILLER	Meals	3226	US BANK	60.11	10/31/2018	2009520	CC Recap-Greg C. Miller	GRE Meeting (3)	10/2018-GCM	10/31/2018	AMS
258	GREG MILLER	Meals	3226	US BANK	28.50	10/31/2018	2009520	CC Recap-Greg C. Miller	Mtg with CIS manager (2)	10/2018-GCM	10/31/2018	AMS
259	GREG MILLER	Meals	3226	US BANK	28.82	10/31/2018	2009520	CC Recap-Greg C. Miller	Field visits (2)	10/2018-GCM	10/31/2018	AMS
260	JEFFREY SCHOENECKER	Meals	3226	US BANK	62.49	10/31/2018	2009520	CC Recap-Jeffrey L Schoenecker	Storm restoration discussion (4)	10/2018-JLS	10/31/2018	AUO
261	CRAIG TURNER	Lodging	3226	US BANK	1,624.17	10/31/2018	2009520	CC Recap-Craig C. Turner	Itron AMI Training & Users Group	10/2018-CCT	10/31/2018	AGI2018
262	CRAIG TURNER	Other Travel	4042	CRAIG TURNER	305.43	10/31/2018	361935	EXPENSE REPORT	Itron Users Group Mtg.	OCT/2018	10/9/2018	AGI2018
263	CRAIG TURNER	Other Travel	3226	US BANK	8.50	10/31/2018	2009520	CC Recap-Craig C. Turner	CEE meeting	10/2018-CCT	10/31/2018	REG
264	CRAIG TURNER	Other Travel	3226	US BANK	8.00	10/31/2018	2009520	CC Recap-Craig C. Turner	CEE meeting	10/2018-CCT	10/31/2018	REG
265	CRAIG TURNER	Other Travel	3226	US BANK	105.00	10/31/2018	2009520	CC Recap-Craig C. Turner	Itron AMI Training & users group	10/2018-CCT	10/31/2018	AGI2018
266	MICHAEL FOSSE	Other Travel	3226	US BANK	6.50	10/31/2018	2009520	CC Recap-Michael G. Fosse	NCRECA Regional Meeting	10/2018-MGF	10/31/2018	ACS
267	RANDALL POULSON	Cell Phone	232		20.00	10/31/2018	233117	PAYROLL			9/30/2018	AEN
268	RANDALL POULSON	Cell Phone	232		20.00	10/31/2018	233117	PAYROLL			10/4/2018	AEN
269	CRAIG TURNER	Cell Phone	591		20.00	10/31/2018	233120	PAYROLL			9/30/2018	ETS
270	CRAIG TURNER	Cell Phone	591		20.00	10/31/2018	233120	PAYROLL			10/4/2018	ETS
271	JEFFREY SCHOENECKER	Cell Phone	735		20.00	10/31/2018	233140	PAYROLL			9/30/2018	AUO
272	JEFFREY SCHOENECKER	Cell Phone	735		20.00	10/31/2018	233140	PAYROLL			10/4/2018	AUO
273	DOUGLAS LARSON	Cell Phone	753		20.00	10/31/2018	233126	PAYROLL			9/30/2018	AMS
274	DOUGLAS LARSON	Cell Phone	753		20.00	10/31/2018	233126	PAYROLL			10/4/2018	AMS
275	CRAIG TURNER	Dues & Memberships	4042	CRAIG TURNER	294.00	11/30/2018	363477	EXPENSE REPORT	IEEE Annual Membership	NOV/2018	11/27/2018	AMS
276	DOUGLAS LARSON	Airfare	2895	DOUGLAS R LARSON	586.40	11/30/2018	3224	EXPENSE REPORT	NARUC	SEP/2018	10/12/2018	REG
277	MICHAEL FOSSE	Airfare	3226	US BANK	432.40	11/30/2018	2009526	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	11/2018-MGF	11/30/2018	ACS
278	CRAIG TURNER	Mileage	4042	CRAIG TURNER	55.59	11/30/2018	363477	EXPENSE REPORT	MN Power System Conference	NOV/2018	11/27/2018	REGENGINEER
279	CRAIG TURNER	Mileage	4042	CRAIG TURNER	57.23	11/30/2018	363477	EXPENSE REPORT	GRE Long Range Forecasting Mtg	NOV/2018	11/27/2018	ETS
280	CRAIG TURNER	Meals	3226	US BANK	17.96	11/30/2018	2009526	CC Recap-Craig C Turner	AGi project coordination (2)	11/2018-CCT	11/30/2018	AGI
281	CRAIG TURNER	Meals	3226	US BANK	52.83	11/30/2018	2009526	CC Recap-Craig C Turner	Minnesota Power Systems Conference (4)	11/2018-CCT	11/30/2018	EDU
282	CRAIG TURNER	Meals	3226	US BANK	64.80	11/30/2018	2009526	CC Recap-Craig C Turner	Capital Work Plan Review (4)	11/2018-CCT	11/30/2018	ETS
283	DOUGLAS LARSON	Meals	2895	DOUGLAS R LARSON	18.73	11/30/2018	3273	EXPENSE REPORT	NARUC	NOV/2018	12/4/2018	REG
284	GRANT BAUMBERGER	Meals	3226	US BANK	46.00	11/30/2018	2009526	CC Recap-Grant S. Baumberger	MVEC Substations (3)	11/2018-GSB	11/30/2018	SUBO
285	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	97.81	11/30/2018	3273	EXPENSE REPORT	NARUC; PUC - DG Advisory Group	NOV/2018	12/4/2018	REG
286	CRAIG TURNER	Other Travel	3226	US BANK	10.00	11/30/2018	2009526	CC Recap-Craig C Turner	Minnesota Power Systems Conference	11/2018-CCT	11/30/2018	EDU
287	CRAIG TURNER	Other Travel	3226	US BANK	10.00	11/30/2018	2009526	CC Recap-Craig C Turner	Minnesota Power Systems Conference	11/2018-CCT	11/30/2018	EDU
288	CRAIG TURNER	Other Travel	3226	US BANK	12.25	11/30/2018	2009526	CC Recap-Craig C Turner	PUC DG Working Group Mtg	11/2018-CCT	11/30/2018	REG
289	JEFFREY SCHOENECKER	Other Travel	3226	US BANK	10.00	11/30/2018	2009526	CC Recap-Jeffrey L Schoenecker	Minnesota Power Systems Conference	11/2018-JLS	11/30/2018	AUO
290	MICHAEL FOSSE	Other Travel	3226	US BANK	31.06	11/30/2018	2009526	CC Recap-Michael G. Fosse	Miscoded - Other Vehicle	11/2018-MGF	11/30/2018	ACS

Line	Employee	Expense Type	Vendor #	Vendor	Pmt Amount	Dist Date	Check/EFT #	Description	Business Purpose	Invoice	Check Date	Project
291	MICHAEL FOSSE	Other Travel	3226	US BANK	10.00	11/30/2018	2009526	CC Recap-Michael G. Fosse	Minnesota Power Systems Conference	11/2018-MGF	11/30/2018	ACS
292	MICHAEL FOSSE	Other Travel	3226	US BANK	17.00	11/30/2018	2009526	CC Recap-Michael G. Fosse	Dakota County Regional Chamber Event	11/2018-MGF	11/30/2018	COMMREL
293	RANDALL POULSON	Cell Phone	232		32.00	11/30/2018	233519	PAYROLL			10/31/2018	AEN
294	RANDALL POULSON	Cell Phone	232		8.00	11/30/2018	233519	PAYROLL			11/1/2018	AEN
295	CRAIG TURNER	Cell Phone	591		32.00	11/30/2018	233522	PAYROLL			10/31/2018	ETS
296	CRAIG TURNER	Cell Phone	591		8.00	11/30/2018	233522	PAYROLL			11/1/2018	ETS
297	JEFFREY SCHOENECKER	Cell Phone	735		32.00	11/30/2018	233542	PAYROLL			10/31/2018	AUO
298	JEFFREY SCHOENECKER	Cell Phone	735		8.00	11/30/2018	233542	PAYROLL			11/1/2018	AUO
299	DOUGLAS LARSON	Cell Phone	753		32.00	11/30/2018	233528	PAYROLL			10/31/2018	AMS
300	DOUGLAS LARSON	Cell Phone	753		8.00	11/30/2018	233528	PAYROLL			11/1/2018	AMS
301	MICHAEL FOSSE	Airfare	3226	US BANK	30.00	12/31/2018	2009534	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	12/2018-MGF	12/31/2018	ACS
302	MICHAEL FOSSE	Airfare	3226	US BANK	30.00	12/31/2018	2009534	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg	12/2018-MGF	12/31/2018	ACS
303	DOUGLAS LARSON	Meals	3226	US BANK	31.05	12/31/2018	2009534	CC Recap-Douglas R. Larson	NARUC (2)	12/2018-DRL	12/31/2018	REG
304	DOUGLAS LARSON	Meals	3226	US BANK	43.76	12/31/2018	2009534	CC Recap-Douglas R. Larson	PUC Mtg (2)	12/2018-DRL	12/31/2018	REG
305	DOUGLAS LARSON	Meals	3226	US BANK	70.92	12/31/2018	2009534	CC Recap-Douglas R. Larson	Mtg GRE Staff - EV (4)	12/2018-DRL	12/31/2018	POWSUP
306	GREG MILLER	Meals	3226	US BANK	50.29	12/31/2018	2009534	CC Recap-Greg C. Miller	GRE Update Mtg (2)	12/2018-GCM	12/31/2018	AMS
307	GREG MILLER	Meals	3226	US BANK	532.31	12/31/2018	2009534	CC Recap-Greg C. Miller	VP Retirement recognition (7)	12/2018-GCM	12/31/2018	AMS
308	GREG MILLER	Meals	3226	US BANK	33.26	12/31/2018	2009534	CC Recap-Greg C. Miller	VP Review (2)	12/2018-GCM	12/31/2018	AMS
309	DOUGLAS LARSON	Lodging	3226	US BANK	708.75	12/31/2018	2009534	CC Recap-Douglas R. Larson	NARUC	12/2018-DRL	12/31/2018	REG
310	GREG MILLER	Lodging	3226	US BANK	153.63	12/31/2018	2009534	CC Recap-Greg C. Miller	GRE Board Meeting	12/2018-GCM	12/31/2018	AMS
311	MICHAEL FOSSE	Lodging	3226	US BANK	459.30	12/31/2018	2009534	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	12/2018-MGF	12/31/2018	ACS
312	DOUGLAS LARSON	Other Travel	2895	DOUGLAS R LARSON	95.00	12/31/2018	3320	EXPENSE REPORT		DEC/2018	1/9/2019	AMS
313	DOUGLAS LARSON	Other Travel	3226	US BANK	5.00	12/31/2018	2009534	CC Recap-Douglas R. Larson	CEE meeting	12/2018-DRL	12/31/2018	REG
314	DOUGLAS LARSON	Other Travel	3226	US BANK	9.00	12/31/2018	2009534	CC Recap-Douglas R. Larson	PUC Meeting	12/2018-DRL	12/31/2018	REG
315	MICHAEL FOSSE	Other Travel	3226	US BANK	27.95	12/31/2018	2009534	CC Recap-Michael G. Fosse	Touchstone Energy BOD Mtg.	12/2018-MGF	12/31/2018	ACS
316	MICHAEL FOSSE	Other Travel	3226	US BANK	10.70	12/31/2018	2009534	CC Recap-Michael G. Fosse	Miscoded - Other Vehicle	12/2018-MGF	12/31/2018	ACS
317	RANDALL POULSON	Cell Phone	232		40.00	12/31/2018	234127	PAYROLL			12/13/2018	AEN
318	CRAIG TURNER	Cell Phone	591		40.00	12/31/2018	234130	PAYROLL			12/13/2018	ETS
319	JEFFREY SCHOENECKER	Cell Phone	735		40.00	12/31/2018	234150	PAYROLL			12/13/2018	AUO
320	DOUGLAS LARSON	Cell Phone	753		40.00	12/31/2018	234136	PAYROLL			12/13/2018	AMS

Top Ten Employee Expenses	**$ 33,752.16**
AGI2018	*$ 10,021.55*
Top Ten Employee Expenses w/o AGI2018	**$ 23,730.61**

Workpaper 14
Property Tax Detail

Dakota Electric Association

Actual & Estimated Property & Real Estate Taxes

		2017 Actual Taxes (Payable 2018)			2018 Actual Taxes (Payable 2019)				2019 Estimated Taxes (Payable 2020)			
	Property I.D.	Taxes	Assessed Value	Rate	Taxes	Assessed Value	Rate		Taxes	Assessed Value	Rate	
PERSONAL PROPERTY TAX	**Distribution Lines**											
Dakota County												
Apple Valley / 196	01-99999-00-003	$ 525,995	$ 15,367,400	3.423%	$ 522,580	$ 15,665,200	3.336%		$ 530,846	$ 15,665,200	3.389%	E
Apple Valley / 191	01-99999-00-004	5,285	151,600	3.486%	5,159	152,300	3.387%		5,241	152,300	3.441%	E
Burnsville / 191	02-99999-00-007	313,106	8,988,700	3.483%	307,371	9,016,500	3.409%		312,233	9,016,500	3.463%	E
Burnsville / 194	02-99999-00-008	42,467	1,189,500	3.570%	41,367	1,176,600	3.516%		42,021	1,176,600	3.571%	E
Burnsville / 196	02-99999-00-009	201,143	5,882,500	3.419%	196,141	5,846,100	3.355%		199,243	5,846,100	3.408%	E
Burnsville Sub / 196 (Leased Land)	02-99999-00-010	24,859	727,000	3.419%	24,448	728,700	3.355%		24,835	728,700	3.408%	E
Burnscott Sub / 191 (Leased Land)	02-99999-01-091	16,180	464,500	3.483%	15,866	465,400	3.409%		16,117	465,400	3.463%	E
Castle Rock Twp (Randolph) / 195	07-99999-00-024	2,424	85,800	2.825%	2,398	85,000	2.821%		2,436	85,000	2.866%	E
Eagan / 191	10-99999-00-009	48,718	1,433,200	3.399%	54,923	1,666,200	3.296%		55,792	1,666,200	3.348%	E
Eagan / 196	10-99999-00-010	545,147	16,342,300	3.336%	532,122	16,414,900	3.242%		540,539	16,414,900	3.293%	E
Eagan / 197	10-99999-00-011	81,900	2,537,800	3.227%	84,575	2,646,600	3.196%		85,913	2,646,600	3.246%	E
Pilot Knob Sub / 196 (Leased Land)	10-99999-12-037	15,408	461,900	3.336%	15,051	464,300	3.242%		15,289	464,300	3.293%	E
Eagan Sub / 196 Westcott (L.L.)	10-99999-12-038	34,242	1,026,500	3.336%	32,965	1,016,900	3.242%		33,486	1,016,900	3.293%	E
Farmington / 192	14-99999-00-001	121,432	3,120,200	3.892%	118,089	3,116,700	3.789%		119,957	3,116,700	3.849%	E
Hastings / 200	19-99999-00-004	30,577	842,200	3.631%	30,069	849,500	3.540%		30,545	849,500	3.596%	E
Inver Grove Heights / 199	20-99999-00-002	24,953	720,000	3.466%	23,214	676,200	3.433%		23,581	676,200	3.487%	E
Inver Grove Heights / 196	20-99999-00-003	79,103	2,247,700	3.519%	78,962	2,263,300	3.489%		80,211	2,263,300	3.544%	E
Lakeville / 196	22-99999-00-004	73,172	2,197,000	3.331%	93,989	2,891,100	3.251%		95,476	2,891,100	3.302%	E
Lakeville / 194	22-99999-00-005	386,910	11,123,700	3.478%	393,414	11,538,200	3.410%		399,637	11,538,200	3.464%	E
Lakeville / 192	22-99999-00-010	49,416	1,355,900	3.645%	52,720	1,477,800	3.567%		53,554	1,477,800	3.624%	E
Miesville / 200	28-99999-00-001	2,287	71,400	3.203%	2,373	76,100	3.118%		2,411	76,100	3.168%	E
New Trier / 200	29-99999-00-001	103	2,900	3.552%	102	2,900	3.517%		104	2,900	3.586%	E
Rosemount / 200	34-99999-00-003	31	900	3.444%	29	900	3.222%		29	900	3.222%	E
Rosemount / 196	34-99999-00-004	71,187	2,103,600	3.384%	71,407	2,171,100	3.289%		72,536	2,171,100	3.341%	E
Scott County												
Lake Marion Sub / 194 (Leased Land)	P080000150	9,482	291,000	3.258%	9,202	288,300	3.192%		9,348	288,300	3.242%	E
Goodhue County												
Cannon Falls Twp	52-999-0220	5,520	149,000	3.705%	5,590	147,600	3.787%		5,678	147,600	3.847%	E
Burnside Twp (Redwing)	55-999-7095	21,032	626,500	3.357%	21,058	620,700	3.393%		21,391	620,700	3.446%	E
Great River Energy												
Empire Sub / 192	12-99999-035-01	13,979	392,200	3.564%	14,224	392,200	3.627%	E	14,449	392,200	3.684%	E
Xcel Energy												
Vermillion Sub / 192		21,363	548,200	3.897%	21,737	548,200	3.965%	E	22,081	548,200	4.028%	E
Total Personal Property Taxes		2,767,421	80,451,100	3.440%	2,771,145	82,405,500	3.363%		2,814,979	82,405,500	3.416%	

Dakota Electric Association

Actual & Estimated Property & Real Estate Taxes

		2017 Actual Taxes (Payable 2018)			2018 Actual Taxes (Payable 2019)				2019 Estimated Taxes (Payable 2020)			
	Property I.D.	Taxes	Assessed Value	Rate	Taxes	Assessed Value	Rate		Taxes	Assessed Value	Rate	
REAL ESTATE TAX	**Substations**											
Dakota County												
Fischer Sub - Apple Valley / 196	01-03400-03-011	47,522	1,386,200	3.428%	46,314	1,386,300	3.341%		47,047	1,386,300	3.394%	E
Apple Valley Sub - Apple Valley / 196	01-23100-01-010	27,584	804,600	3.428%	27,552	824,700	3.341%		27,988	824,700	3.394%	E
Colonial Hills Sub - Burnsville / 191	02-02400-54-040	34,927	1,002,700	3.483%	34,216	1,003,700	3.409%		34,757	1,003,700	3.463%	E
Castle Rock Sub South / 659	07-03700-00-141	4,320	129,400	3.338%	4,314	132,200	3.263%		4,382	132,200	3.315%	E
Castle Rock Sub North / 659	07-18200-00-052	44	1,300	3.385%	46	1,400	3.286%		47	1,400	3.357%	E
Lemay Sub West - Eagan / 197	10-01000-56-011	1,617	50,100	3.228%	1,601	50,100	3.196%		1,626	50,100	3.246%	E
Lemay Sub East - Eagan / 197	10-01000-56-020	28,067	869,700	3.227%	27,901	873,100	3.196%		28,342	873,100	3.246%	E
Deerwood Sub - Eagan Sub / 196	10-02000-75-020	22,587	677,100	3.336%	21,930	676,500	3.242%		22,277	676,500	3.293%	E
Lebanon Hills Sub - Eagan / 196	10-03600-25-029	12,899	386,700	3.336%								
Eagan Sub / 196	10-22485-01-010	25,226	756,200	3.336%	24,342	750,900	3.242%		24,727	750,900	3.293%	E
4627 Dodd Rd	10-44620-01-010				12,818	395,400	3.242%		13,021	395,400	3.293%	E
River Hills Sub - Eagan / 196	10-64405-01-010	48,502	1,454,000	3.336%	47,442	1,463,500	3.242%		48,192	1,463,500	3.293%	E
Yankee Doodle Sub - Eagan / 196	10-87400-01-010	32,688	979,900	3.336%	31,357	967,300	3.242%		31,853	967,300	3.293%	E
Headquarters Building **	14-00600-27-012	157,830	4,102,700	3.847%	154,459	4,102,700	3.119%		156,902	4,102,700	3.824%	E
Farmington Sub / 192	14-03600-07-010	2,650	68,000	3.897%	2,641	69,600	2.721%		2,683	69,600	3.824%	E
Randolph Sub / 195	17-03200-50-021	10,263	369,800	2.775%	22,056	776,400	3.795%		22,405	776,400	3.855%	E
Rich Valley Sub - Inver Grove / 196	20-64033-01-010	4,184	118,900	3.519%	4,082	117,000	2.841%		4,147	117,000	2.886%	E
Orchard Lake Sub - Lakeville / 194	22-00110-30-011	18,295	526,000	3.478%	18,576	544,800	3.489%		18,870	544,800	3.544%	E
Lakeville Par 7 / 196	22-00200-01-019	9	600	1.500%	10	700	3.410%		10	700	3.464%	E
Dakota Heights Sub - Lakeville / 194	22-00600-78-012	21,555	619,700	3.478%	21,451	629,100	1.429%		21,790	629,100	1.429%	E
Dodd Park Sub South - Lakeville / 194	22-00900-79-012	300	8,600	3.488%								
Dodd Park Sub North - Lakeville / 194	22-00900-79-013	20,654	592,900	3.484%								
17709 Cedar Ave	22-00900-79-014				20,666	605,200	3.415%		20,993	605,200	3.469%	E
Kenrick Sub - Lakeville / 194	22-44345-01-010	31,670	909,100	3.484%	31,477	921,800	3.415%		31,975	921,800	3.469%	E
Lakeville Sub / 196	22-44420-01-010	17,447	523,000	3.336%	17,560	539,300	3.415%		17,838	539,300	3.308%	E
Ritter Sub / 194	22-76704-01-010	36,135	1,092,400	3.308%	36,133	1,112,900	3.415%		36,705	1,112,900	3.298%	E
Hastings Sub / 200 (DEA Portion)	25-00700-01-012	14,695	474,100	3.100%	14,354	477,800	3.256%		14,581	477,800	3.052%	E
Marshan Twp / 200	25-01300-50-017	12,509	403,600	3.099%	10,530	350,500	3.247%		10,697	350,500	3.052%	E
Miesville Sub South / 200	28-01300-30-010	13,259	414,000	3.203%	13,151	421,700	3.004%		13,359	421,700	3.168%	E
Miesville Sub Northwest / 200	28-01300-31-016	2,402	75,000	3.203%	2,420	77,600	3.004%		2,458	77,600	3.168%	E
Nininger Sub / 200	30-03000-28-020	19,310	694,000	2.782%	19,161	704,100	3.119%		19,464	704,100	2.764%	E
Goodhue County												
Byllesby Sub - Cannon Falls Twp	28-006-0200	6,714	250,500	2.680%	7,090	262,400	2.702%		7,202	262,400	2.745%	E
Ravenna Sub	55-705-0171	30,954	842,900	3.672%	32,368	874,300	3.702%		32,880	874,300	3.761%	E
MN Valley Electric												
Burnscott Joint Sub (land)	02-15385-100-02	4,190			4,263			E	4,330			E
Additional Taxes												
City of Eagan Assessment Yankee Doodle Sub		1,789										
ISD199 Additonal Referendum		176										
Xcel Energy												
Vermillion Sub / 192	14-02500-020-82	11,104	284,950	3.897%	11,298	284,950	3.965%	E	11,473	284,950	4.026%	E
Total Real Estate Taxes		724,077	20,868,650	3.470%	723,579	21,397,950	3.382%		735,021	21,397,950	3.435%	
Subtotal Personal and Real Estate Taxes Payable		3,491,498	101,319,750	3.446%	3,494,724	103,803,450	3.367%		3,550,000	103,803,450	3.420%	

Workpaper 13
Sales History and Forecasted Test Year Normalization

Dakota Electric Association
Sales History and Forecasted Test Year Normalization

Enclosed are schedules supporting the test year energy sales figures used in Exhibit (DEA_1) page 12 of 22.

Dakota Electric has experienced an overall downward trend in average kWh per member per month over the last ten years. Our highest level of total kWh sales was achieved in 2007 with 1,897,654,115 kWh sold and 99,959 members/meters at the end of the year. In 2018 we sold 1,851,702,114 kWhs while 107,974 members/meters were served at the end of the year. This makes it challenging to estimate kWh for the adjusted test year. We look at ten-year trends as well as the 2019 budget. We use the higher of the budget or the ten-year trend line in these estimates.

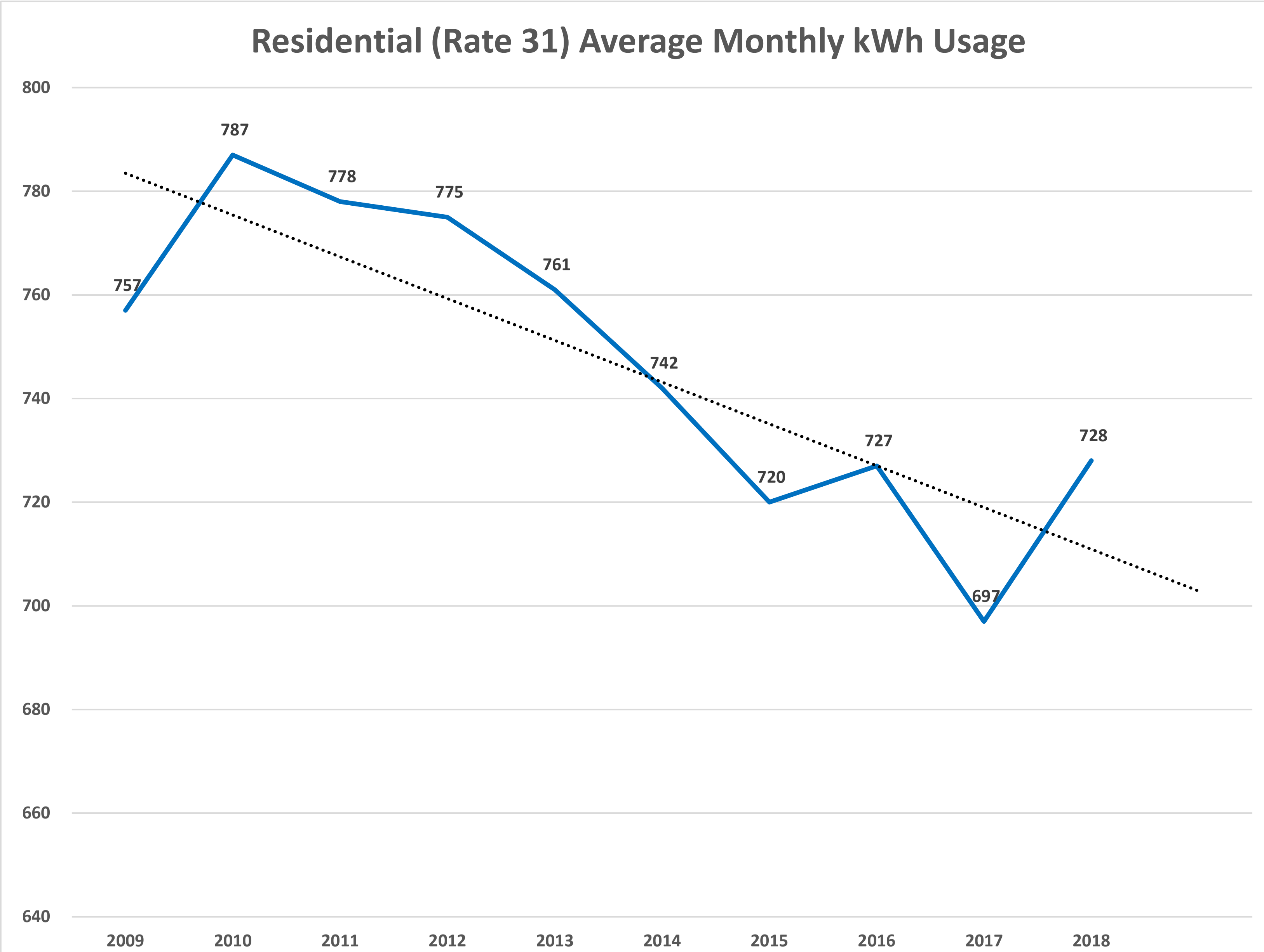
For Rate 31 (Residential) which is the most weather sensitive rate class, energy sales are based on a regression analysis (LINEST function) using a ten-year trend of average monthly sales (2009-2018), weather normalized (using 20 years of weather), multiplied by budgeted 2019 number of members.

For Rates 41 (Small General Service), 46 (General Service) and 70 (Interruptible Service – Full) energy sales are based on the 2019 budgeted average kWh per month.

For Rate 71 (Interruptible Service – Partial), energy sales are based on the ten-year average (2009-2018) kWh per month trend multiplied by budgeted 2019 number of members.

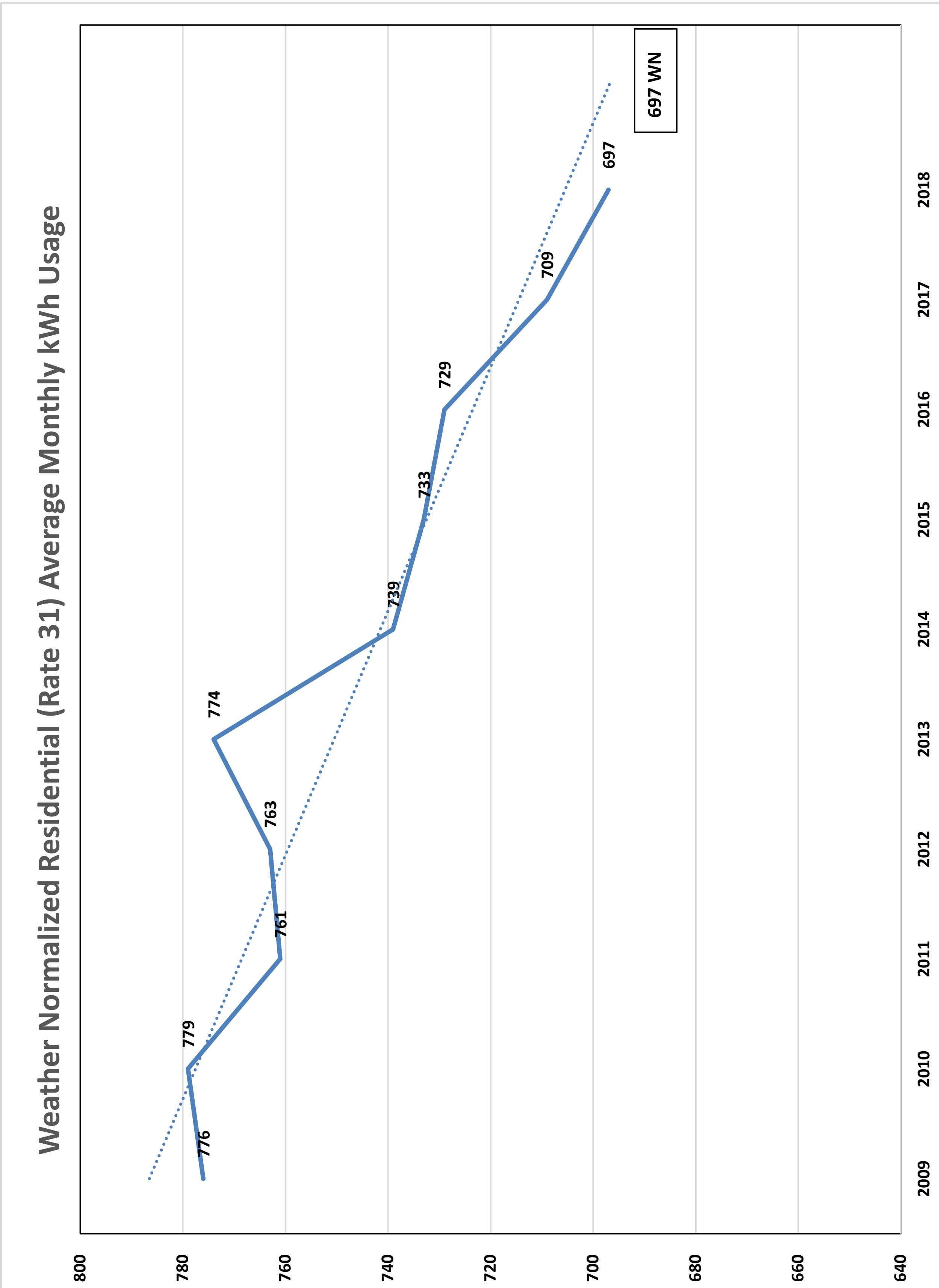
Dakota Electric Association
Residential History - Rate 31 Excluding 51 & 52 & 81

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Monthly Average
2018														
kWh	74,407,414	63,211,669	61,569,961	57,044,338	70,585,388	82,550,222	95,558,159	92,341,426	70,140,204	62,226,667	64,270,979	73,586,800	867,493,227	
# Consumers	*98,778*	*98,863*	*98,948*	*99,063*	*99,264*	*99,305*	*99,383*	*99,439*	*99,629*	*99,613*	*99,741*	*99,837*		*99,322*
Average kWh	753	639	622	576	711	831	962	929	704	625	644	737	8,733	728
2017														
kWh	72,717,202	55,394,163	62,143,275	53,729,827	56,510,906	77,991,980	97,613,456	73,934,788	71,652,724	59,632,240	61,769,727	76,912,070	820,002,358	
# Consumers	*97,520*	*97,654*	*97,717*	*97,715*	*97,774*	*97,900*	*97,930*	*98,027*	*98,171*	*98,402*	*98,653*	*98,716*		*98,015*
Average kWh	746	567	636	550	578	797	997	754	730	606	626	779	8,366	697
2016														
kWh	72,671,837	61,325,062	58,414,916	54,902,116	62,005,669	78,711,934	99,767,555	93,558,197	69,160,780	60,426,646	59,560,470	75,132,857	845,638,039	
# Consumers	*96,555*	*96,633*	*96,731*	*96,758*	*96,771*	*96,851*	*96,905*	*96,953*	*97,097*	*97,283*	*97,395*	*97,460*		*96,949*
Average kWh	753	635	604	567	641	813	1,030	965	712	621	612	771	8,724	727
2015														
kWh	72,489,731	64,101,216	62,083,472	52,357,214	57,125,791	75,227,619	94,059,185	85,853,672	74,491,953	59,164,183	61,190,177	71,836,313	829,980,526	
# Consumers	*95,896*	*95,937*	*95,972*	*95,954*	*96,006*	*96,043*	*96,067*	*96,116*	*96,238*	*96,331*	*96,412*	*96,483*		*96,121*
Average kWh	756	668	647	546	595	783	979	893	774	614	635	745	8,635	720
2014														
kWh	80,017,109	67,943,393	65,792,189	57,214,179	61,070,612	75,987,490	85,105,982	90,332,933	65,266,061	58,350,506	67,900,011	74,861,178	849,841,643	
# Consumers	*95,313*	*95,333*	*95,371*	*95,317*	*95,310*	*95,417*	*95,437*	*95,498*	*95,517*	*95,661*	*95,713*	*95,783*		*95,473*
Average kWh	840	713	690	600	641	796	892	946	683	610	709	782	8,902	742
2013														
kWh	76,240,051	62,500,960	65,845,676	58,926,579	58,589,617	74,899,653	98,321,223	93,515,230	72,014,345	60,588,735	65,200,198	79,523,284	866,165,551	
# Consumers	*94,686*	*94,736*	*94,792*	*94,745*	*94,768*	*94,816*	*94,819*	*94,891*	*94,960*	*95,063*	*95,165*	*95,242*		*94,890*
Average kWh	805	660	695	622	618	790	1,037	986	758	637	685	835	9,128	761
2012														
kWh	73,438,067	61,666,412	59,413,373	54,768,395	63,913,772	86,590,823	121,105,202	89,600,986	66,978,262	60,604,312	62,626,777	76,238,832	876,945,213	
# Consumers	*94,145*	*94,193*	*94,202*	*94,133*	*94,156*	*94,210*	*94,300*	*94,325*	*94,359*	*94,484*	*94,568*	*94,622*		*94,308*
Average kWh	780	655	631	582	679	919	1,284	950	710	641	662	806	9,299	775
2011														
kWh	78,349,086	64,269,923	65,890,375	57,858,793	58,956,818	74,450,201	116,205,877	94,644,900	66,535,842	62,242,768	63,141,448	74,730,180	877,276,211	
# Consumers	*93,866*	*93,913*	*93,933*	*93,842*	*93,887*	*93,891*	*93,874*	*93,891*	*93,939*	*94,017*	*94,054*	*94,105*		*93,934*
Average kWh	835	684	701	617	628	793	1,238	1,008	708	662	671	794	9,340	778
2010														
kWh	81,134,695	62,633,764	62,578,256	55,175,412	68,722,778	75,474,893	104,269,562	105,477,865	62,014,503	59,972,291	67,522,230	79,767,010	884,743,259	
# Consumers	*93,572*	*93,617*	*93,701*	*93,573*	*93,564*	*93,583*	*93,609*	*93,642*	*93,656*	*93,709*	*93,771*	*93,858*		*93,655*
Average kWh	867	669	668	590	735	807	1,114	1,126	662	640	720	850	9,448	787
2009														
kWh	81,370,780	63,491,283	65,976,809	56,786,158	60,036,272	75,203,661	79,684,496	81,493,523	71,154,214	65,139,191	64,777,241	81,580,178	846,693,806	
# Consumers	*93,160*	*93,176*	*93,184*	*93,040*	*93,072*	*93,120*	*93,128*	*93,170*	*93,194*	*93,318*	*93,377*	*93,522*		*93,205*
Average kWh	873	681	708	610	645	808	856	875	764	698	694	872	9,083	757


Residential (Rate 31) Average Monthly kWh Usage
800
780
760
740
720
700
680
660
640
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
757
787
778
775
761
742
720
727
697
728

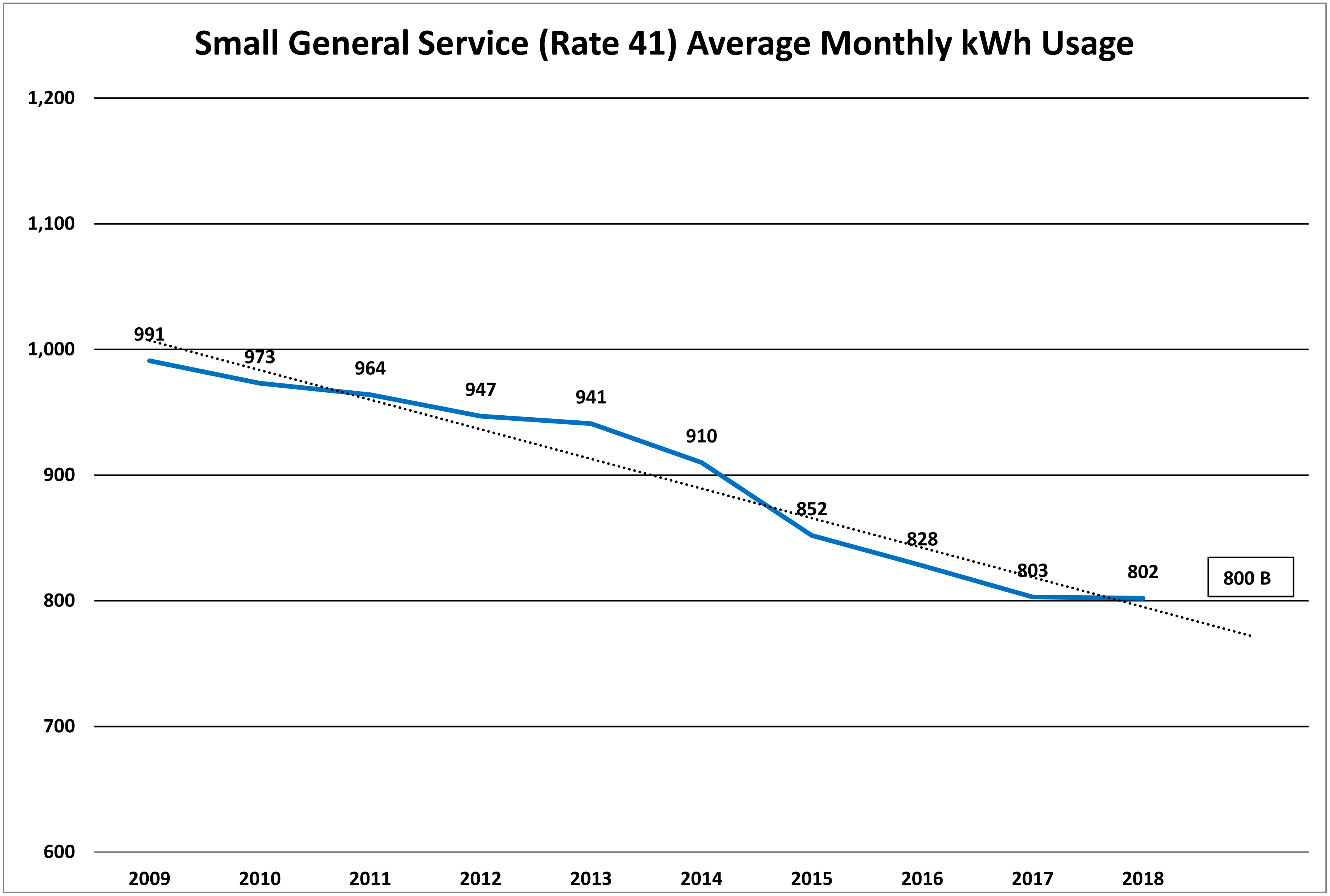
Dakota Electric
Average Residential Monthly Sales
As Reported & Weather Normalized

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Mo Avg
Reported															
2006		795	681	724	594	741	915	1,278	1,011	678	698	715	868	9,698	808
2007	*1.6%*	847	728	712	625	704	958	1,163	1,019	773	716	732	880	9,857	821
2008	*-4.2%*	835	788	732	629	655	764	1,059	983	719	629	738	908	9,439	787
2009	*-3.8%*	873	681	708	610	645	808	856	875	764	698	694	872	9,084	757
2010	*4.0%*	867	669	668	590	735	807	1,114	1,126	662	640	720	850	9,448	787
2011	*-1.2%*	835	684	701	617	628	793	1,238	1,008	708	662	671	794	9,339	778
2012	*-0.4%*	780	655	631	582	679	919	1,284	950	710	641	662	806	9,299	775
2013	*-1.8%*	805	660	695	622	618	790	1,037	986	758	637	685	835	9,128	761
2014	*-2.5%*	840	713	690	600	641	796	892	946	683	610	709	782	8,902	742
2015	*-3.0%*	756	668	647	546	595	783	979	893	774	614	635	745	8,635	720
2016	*1.0%*	753	635	604	567	641	813	1,030	965	712	621	612	771	8,724	727
2017	*-4.1%*	746	567	636	550	578	797	997	754	730	606	626	779	8,366	697
2018	*4.4%*	753	639	622	576	711	831	962	929	704	625	644	737	8,733	728
Weather Normalized															
2006		848	681	725	624	685	886	1,124	1,010	718	676	717	902	9,596	800
2007	*0.6%*	860	702	733	610	679	881	1,139	1,011	748	706	724	858	9,651	804
2008	*-2.2%*	820	762	710	619	689	823	1,050	971	749	637	731	873	9,434	786
2009	*-1.3%*	837	685	703	613	661	827	1,039	946	746	680	722	853	9,312	776
2010	*0.4%*	851	668	702	626	684	850	1,082	947	750	647	716	827	9,350	779
2011	*-2.3%*	815	679	683	616	647	799	1,115	953	696	627	684	822	9,136	761
2012	*0.2%*	810	681	676	597	656	855	1,112	950	699	642	666	814	9,158	763
2013	*1.4%*	807	656	667	595	610	806	1,061	1,110	863	645	672	795	9,287	774
2014	*-4.5%*	802	668	655	584	632	817	1,022	903	711	619	663	794	8,870	739
2015	*-0.8%*	767	633	656	560	621	813	1,051	926	705	627	657	783	8,799	733
2016	*-0.6%*	757	649	639	563	623	788	1,035	919	717	644	645	768	8,747	729
2017	*-2.8%*	765	612	638	567	609	763	997	870	675	623	617	767	8,503	709
2018	*-1.6%*	753	623	618	533	604	765	975	854	659	619	610	756	8,369	697


Weather Normalized Residential (Rate 31) Average Monthly kWh Usage
800
780
760
740
720
700
680
660
640
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
776
779
761
763
774
739
733
729
709
697
697 WN

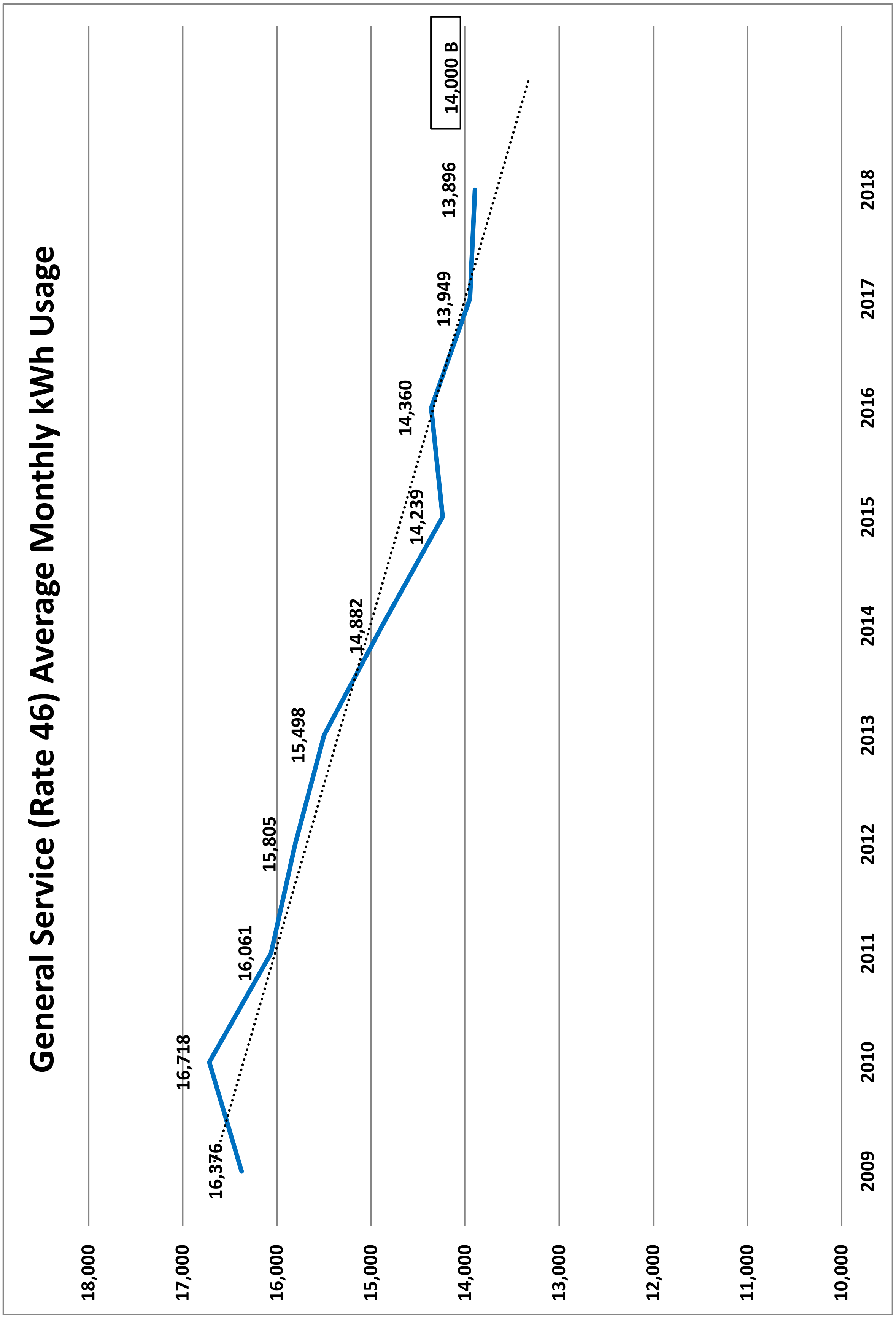
Dakota Electric Association
Small General Service - Rate 41
Excluding 51/52

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Monthly Average
2018														
kWh	4,125,666	3,750,188	3,645,342	3,377,291	3,547,083	3,612,078	3,757,652	3,356,732	3,063,432	2,824,252	3,629,681	3,884,334	42,573,731	
# Consumers	*4,393*	*4,388*	*4,397*	*4,403*	*4,419*	*4,421*	*4,444*	*4,452*	*4,462*	*4,440*	*4,445*	*4,450*		*4,426*
Average kWh	939	855	829	767	803	817	846	754	687	636	817	873	9,623	802
2017														
kWh	4,089,924	3,568,353	3,579,498	3,169,466	3,251,781	3,673,061	3,964,752	3,054,440	3,266,357	2,815,940	3,581,965	3,981,082	41,996,619	
# Consumers	*4,344*	*4,349*	*4,342*	*4,338*	*4,350*	*4,356*	*4,356*	*4,361*	*4,363*	*4,359*	*4,384*	*4,390*		*4,358*
Average kWh	942	820	824	731	748	843	910	700	749	646	817	907	9,637	803
2016														
kWh	4,095,302	3,816,209	3,591,990	3,275,583	3,352,335	3,772,085	3,814,592	3,716,283	2,902,062	3,047,762	3,352,355	4,102,162	42,838,720	
# Consumers	*4,305*	*4,306*	*4,308*	*4,307*	*4,308*	*4,300*	*4,296*	*4,303*	*4,310*	*4,312*	*4,337*	*4,349*		*4,312*
Average kWh	951	886	834	761	778	877	888	864	673	707	773	943	9,935	828
2015														
kWh	4,405,928	4,064,419	3,823,002	3,419,244	3,423,880	3,752,852	3,908,117	3,463,707	3,380,559	2,992,717	3,401,914	3,906,973	43,943,312	
# Consumers	*4,313*	*4,315*	*4,307*	*4,296*	*4,300*	*4,291*	*4,291*	*4,288*	*4,283*	*4,286*	*4,287*	*4,299*		*4,296*
Average kWh	1,022	942	888	796	796	875	911	808	789	698	794	909	10,228	852
2014														
kWh	4,890,935	4,315,180	4,469,292	3,774,583	3,871,927	3,960,022	3,798,582	3,959,273	3,068,618	3,358,039	3,903,311	4,292,411	47,662,173	
# Consumers	*4,425*	*4,415*	*4,409*	*4,400*	*4,384*	*4,351*	*4,340*	*4,329*	*4,333*	*4,341*	*4,333*	*4,318*		*4,365*
Average kWh	1,105	977	1,014	858	883	910	875	915	708	774	901	994	10,914	910
2013														
kWh	4,506,583	4,165,932	4,295,302	3,914,972	3,829,695	4,130,767	4,375,315	4,519,084	3,444,358	3,685,893	4,108,387	4,926,192	49,902,480	
# Consumers	*4,419*	*4,422*	*4,421*	*4,415*	*4,423*	*4,425*	*4,419*	*4,424*	*4,416*	*4,415*	*4,416*	*4,419*		*4,420*
Average kWh	1,020	942	972	887	866	934	990	1,021	780	835	930	1,115	11,292	941
2012														
kWh	4,480,020	4,359,294	4,210,386	3,832,376	4,203,034	4,544,112	4,950,615	3,998,576	3,593,446	3,716,191	3,943,252	4,511,911	50,343,213	
# Consumers	*4,397*	*4,397*	*4,461*	*4,454*	*4,457*	*4,455*	*4,446*	*4,427*	*4,417*	*4,424*	*4,426*	*4,423*		*4,432*
Average kWh	1,019	991	944	860	943	1,020	1,113	903	814	840	891	1,020	11,358	947
2011														
kWh	5,031,725	4,493,900	4,462,936	3,896,317	4,028,366	4,388,167	5,038,104	3,986,200	3,630,574	3,810,856	4,104,432	4,554,627	51,426,204	
# Consumers	*4,504*	*4,499*	*4,490*	*4,479*	*4,472*	*4,462*	*4,441*	*4,395*	*4,396*	*4,388*	*4,394*	*4,396*		*4,443*
Average kWh	1,117	999	994	870	901	983	1,134	907	826	868	934	1,036	11,569	964
2010														
kWh	4,975,621	4,399,444	4,344,251	3,879,782	4,301,771	4,147,756	4,701,482	4,905,177	3,454,479	4,183,334	4,140,347	4,923,932	52,357,376	
# Consumers	*4,465*	*4,456*	*4,476*	*4,463*	*4,475*	*4,460*	*4,496*	*4,516*	*4,491*	*4,488*	*4,505*	*4,504*		*4,483*
Average kWh	1,114	987	971	869	961	930	1,046	1,086	769	932	919	1,093	11,677	973
2009														
kWh	5,159,913	4,356,653	4,440,021	3,962,628	4,034,113	4,407,740	4,017,383	4,530,839	4,029,575	3,902,528	4,214,659	4,883,368	51,939,420	
# Consumers	*4,311*	*4,312*	*4,342*	*4,368*	*4,370*	*4,368*	*4,368*	*4,377*	*4,372*	*4,378*	*4,410*	*4,457*		*4,369*
Average kWh	1,197	1,010	1,023	907	923	1,009	920	1,035	922	891	956	1,096	11,889	991


Small General Service (Rate 41) Average Monthly kWh Usage
1,200
1,100
1,000
900
800
700
600
991
973
964
947
941
910
852
828
803
802
800 B
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018

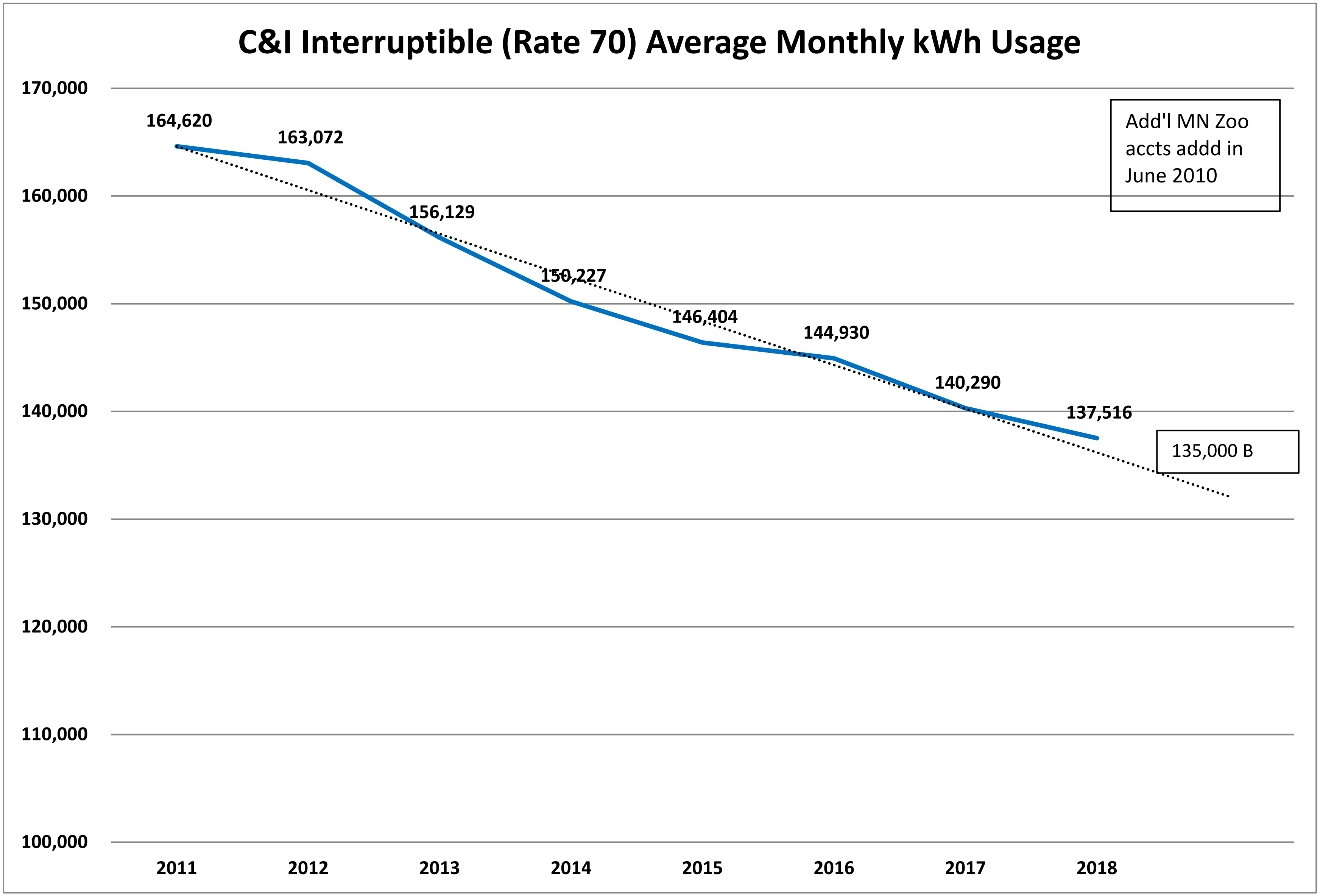
Dakota Electric Association
General Service - Rate 46

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Monthly Average
2018														
kWh	37,960,879	33,666,916	35,426,168	32,750,828	38,857,855	43,337,283	44,292,920	41,072,366	38,434,968	31,390,301	36,615,834	35,797,975	449,604,293	
# Consumers	*2,687*	*2,695*	*2,695*	*2,695*	*2,699*	*2,700*	*2,704*	*2,705*	*2,703*	*2,686*	*2,689*	*2,692*		*2,697*
Average kWh	14,128	12,492	13,145	12,152	14,397	16,051	16,381	15,184	14,219	11,687	13,617	13,298	166,751	13,896
2017														
kWh	36,496,535	33,780,124	34,340,412	31,192,477	35,908,841	41,704,699	44,780,899	38,795,083	38,520,221	33,535,943	37,174,237	37,896,422	444,125,893	
# Consumers	*2,638*	*2,640*	*2,640*	*2,645*	*2,645*	*2,648*	*2,646*	*2,652*	*2,659*	*2,676*	*2,676*	*2,676*		*2,655*
Average kWh	13,835	12,796	13,008	11,793	13,576	15,750	16,924	14,629	14,487	12,532	13,892	14,162	167,384	13,949
2016														
kWh	37,752,226	33,705,421	33,440,742	31,893,659	34,988,684	44,799,989	42,941,628	43,340,550	34,405,519	34,887,254	35,973,961	39,782,435	447,912,068	
# Consumers	*2,585*	*2,589*	*2,583*	*2,584*	*2,590*	*2,590*	*2,595*	*2,598*	*2,612*	*2,620*	*2,619*	*2,627*		*2,601*
Average kWh	14,604	13,019	12,946	12,343	13,509	17,297	16,548	16,682	13,172	13,316	13,736	15,144	172,316	14,360
2015														
kWh	37,151,359	34,136,026	31,880,426	32,384,617	34,328,013	39,244,019	44,116,348	38,909,407	38,696,338	32,952,351	34,133,372	37,074,748	435,007,024	
# Consumers	*2,516*	*2,516*	*2,523*	*2,525*	*2,528*	*2,544*	*2,549*	*2,554*	*2,563*	*2,571*	*2,579*	*2,580*		*2,548*
Average kWh	14,766	13,568	12,636	12,826	13,579	15,426	17,307	15,235	15,098	12,817	13,235	14,370	170,863	14,239
2014														
kWh	37,264,553	32,425,252	34,820,199	31,521,777	34,957,873	40,504,990	41,243,718	42,950,155	34,050,791	34,465,582	35,737,088	37,045,567	436,987,545	
# Consumers	*2,384*	*2,391*	*2,393*	*2,396*	*2,411*	*2,440*	*2,463*	*2,484*	*2,489*	*2,485*	*2,499*	*2,520*		*2,452*
Average kWh	15,631	13,561	14,551	13,156	14,499	16,600	16,745	17,291	13,681	13,869	14,301	14,701	178,586	14,882
2013														
kWh	35,826,769	32,713,972	34,301,539	31,941,430	35,161,037	37,909,652	43,297,353	42,927,436	35,744,010	35,711,182	34,545,653	38,249,467	438,329,500	
# Consumers	*2,338*	*2,340*	*2,345*	*2,349*	*2,344*	*2,345*	*2,349*	*2,356*	*2,377*	*2,382*	*2,376*	*2,381*		*2,359*
Average kWh	15,324	13,980	14,628	13,598	15,000	16,166	18,432	18,220	15,037	14,992	14,539	16,064	185,980	15,498
2012														
kWh	34,479,857	33,156,111	32,550,213	31,424,360	36,978,047	40,675,869	45,686,373	37,787,344	35,134,456	33,821,441	34,518,805	36,906,657	433,119,533	
# Consumers	*2,303*	*2,305*	*2,239*	*2,241*	*2,245*	*2,253*	*2,264*	*2,284*	*2,307*	*2,313*	*2,329*	*2,332*		*2,283*
Average kWh	14,972	14,384	14,538	14,022	16,471	18,054	20,179	16,544	15,229	14,622	14,821	15,826	189,662	15,805
2011														
kWh	36,402,472	32,843,047	33,844,567	31,111,015	35,710,804	39,611,509	46,817,661	38,865,355	34,738,356	35,117,286	33,202,092	36,735,698	434,999,862	
# Consumers	*2,217*	*2,223*	*2,228*	*2,233*	*2,233*	*2,237*	*2,272*	*2,273*	*2,278*	*2,294*	*2,294*	*2,298*		*2,260*
Average kWh	16,420	14,774	15,191	13,932	15,992	17,707	20,606	17,099	15,249	15,308	14,473	15,986	192,737	16,061
2010														
kWh	34,768,071	33,827,270	33,280,794	32,086,653	37,520,790	38,059,894	42,997,469	43,148,179	32,193,182	36,445,754	32,752,053	39,276,832	436,356,941	
# Consumers	*2,158*	*2,166*	*2,155*	*2,175*	*2,173*	*2,168*	*2,151*	*2,152*	*2,197*	*2,202*	*2,204*	*2,211*		*2,178*
Average kWh	16,111	15,617	15,444	14,752	17,267	17,555	19,990	20,050	14,653	16,551	14,860	17,764	200,614	16,718
2009														
kWh	37,665,076	32,447,564	34,131,292	31,707,609	35,063,358	38,895,254	37,062,937	40,964,536	36,771,694	32,992,592	32,827,705	39,071,430	429,601,047	
# Consumers	*2,215*	*2,211*	*2,197*	*2,178*	*2,171*	*2,176*	*2,192*	*2,184*	*2,185*	*2,189*	*2,169*	*2,170*		*2,184*
Average kWh	17,005	14,676	15,535	14,558	16,151	17,875	16,908	18,757	16,829	15,072	15,135	18,005	196,506	16,376


General Service (Rate 46) Average Monthly kWh Usage
18,000
17,000
16,000
15,000
14,000
13,000
12,000
11,000
10,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
16,376
16,718
16,061
15,805
15,498
14,882
14,239
14,360
13,949
13,896
14,000 B

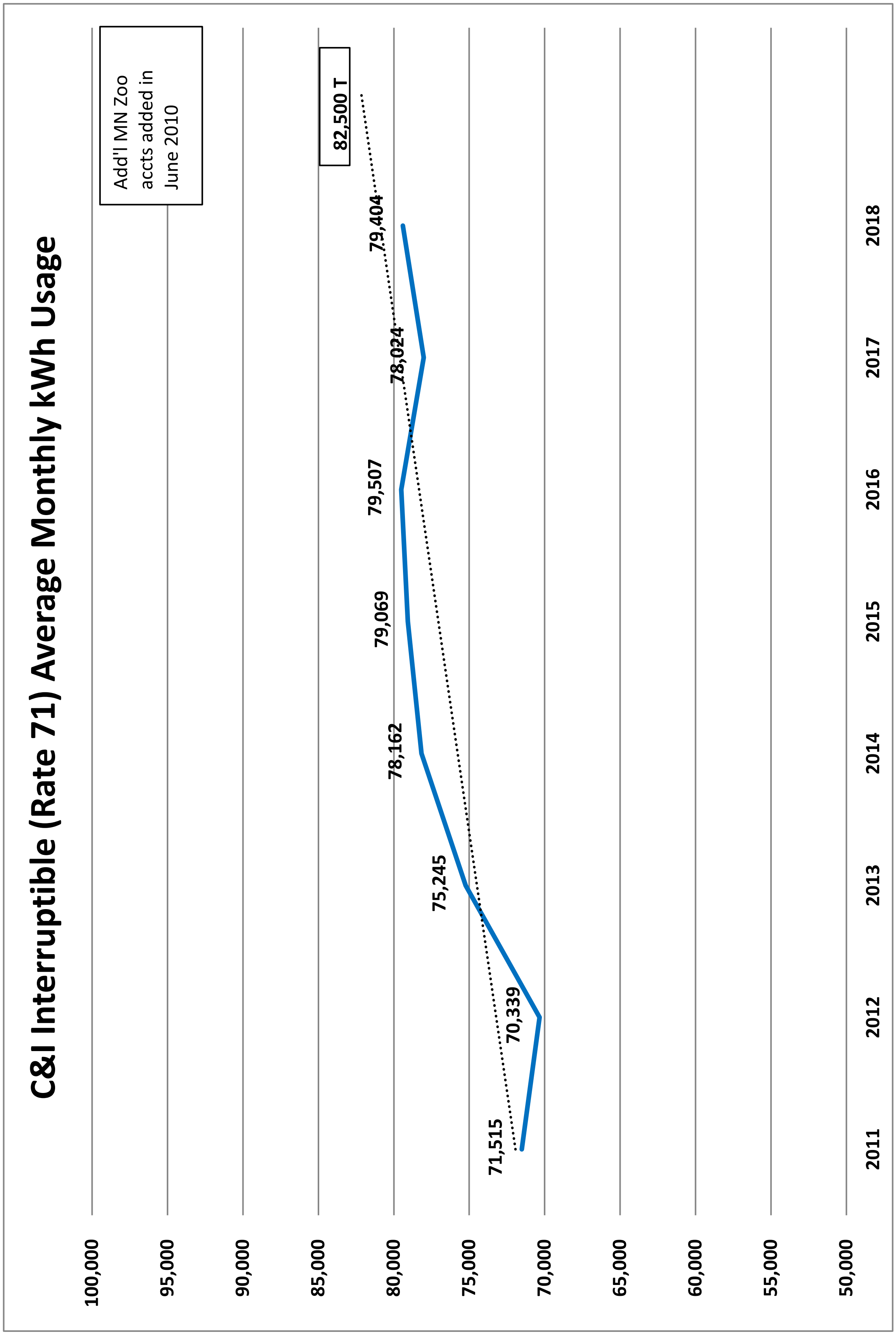
Dakota Electric Association
Full Interruptible Service - Rate 70

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Monthly Average
2018														
kWh	30,622,046	27,669,400	29,653,518	28,846,311	34,741,023	35,173,960	37,349,811	37,670,413	33,196,188	30,335,042	29,178,956	29,821,368	384,258,036	
# Meters	*231*	*231*	*231*	*231*	*233*	*233*	*233*	*233*	*234*	*234*	*235*	*235*		*233*
Average kWh	132,563	119,781	128,370	124,876	149,103	150,961	160,300	161,676	141,864	129,637	124,166	126,899	1,650,196	137,516
2017														
kWh	30,792,518	27,799,302	30,715,270	29,759,743	32,704,146	35,573,962	37,331,643	35,837,960	34,227,595	31,337,126	29,093,052	30,275,977	385,448,294	
# Meters	*229*	*229*	*229*	*228*	*228*	*228*	*228*	*229*	*229*	*230*	*230*	*231*		*229*
Average kWh	134,465	121,394	134,128	130,525	143,439	156,026	163,735	156,498	149,465	136,248	126,492	131,065	1,683,480	140,290
2016														
kWh	30,635,124	28,765,062	30,457,608	29,787,009	33,055,514	35,521,428	37,195,761	37,681,591	34,365,125	31,199,619	29,456,002	31,274,912	389,394,755	
# Meters	*221*	*221*	*221*	*221*	*221*	*225*	*225*	*225*	*227*	*226*	*226*	*227*		*224*
Average kWh	138,620	130,159	137,817	134,783	149,572	157,873	165,314	167,474	151,388	138,051	130,336	137,775	1,739,162	144,930
2015														
kWh	31,018,945	28,494,896	30,869,423	30,435,260	32,832,730	35,101,257	37,035,009	36,592,895	34,894,881	31,224,446	29,549,464	30,377,061	388,426,267	
# Meters	*222*	*223*	*223*	*222*	*222*	*220*	*220*	*220*	*220*	*220*	*221*	*221*		*221*
Average kWh	139,725	127,780	138,428	137,096	147,895	159,551	168,341	166,331	158,613	141,929	133,708	137,453	1,756,850	146,404
2014														
kWh	31,411,957	28,694,262	30,687,893	29,948,653	32,970,645	34,847,029	35,811,446	38,071,040	33,514,460	31,657,450	29,780,107	30,698,786	388,093,728	
# Meters	*211*	*211*	*211*	*211*	*211*	*212*	*216*	*216*	*215*	*224*	*223*	*224*		*215*
Average kWh	148,872	135,992	145,440	141,937	156,259	164,373	165,794	176,255	155,881	141,328	133,543	137,048	1,802,722	150,227
2013														
kWh	32,188,438	28,912,770	30,888,273	30,596,069	33,903,886	35,035,407	37,519,608	37,653,650	34,519,092	32,015,836	30,374,742	31,394,448	395,002,219	
# Meters	*211*	*211*	*211*	*211*	*211*	*211*	*211*	*211*	*210*	*210*	*211*	*211*		*211*
Average kWh	152,552	137,027	146,390	145,005	160,682	166,045	177,818	178,453	164,377	152,456	143,956	148,789	1,873,550	156,129
2012														
kWh	31,980,478	30,355,988	33,252,623	31,454,042	35,851,868	37,189,010	40,632,000	39,099,334	34,841,648	33,617,551	31,569,987	31,982,245	411,826,774	
# Meters	*207*	*210*	*210*	*210*	*211*	*211*	*211*	*211*	*211*	*211*	*211*	*211*		*210*
Average kWh	154,495	144,552	158,346	149,781	169,914	176,251	192,569	185,305	165,126	159,325	149,621	151,575	1,956,860	163,072
2011														
kWh	32,191,276	29,045,174	31,895,200	31,222,940	33,433,640	36,273,005	39,511,825	38,771,108	34,841,618	34,413,364	31,551,607	32,444,470	405,595,227	
# Meters	*203*	*203*	*203*	*204*	*207*	*207*	*206*	*206*	*206*	*206*	*206*	*206*		*205*
Average kWh	158,578	143,080	157,119	153,054	161,515	175,232	191,805	188,209	169,134	167,055	153,163	157,497	1,975,441	164,620
2010														
kWh	31,037,488	28,054,255	31,164,272	31,115,241	33,909,402	36,652,479	38,126,058	37,348,406	34,122,659	33,337,760	31,585,844	32,443,479	398,897,343	
# Meters	*168*	*168*	*167*	*167*	*171*	*200*	*200*	*200*	*200*	*202*	*203*	*203*		*187*
Average kWh	184,747	166,990	186,612	186,319	198,301	183,262	190,630	186,742	170,613	165,038	155,595	159,820	2,134,669	177,889
2009														
kWh	30,328,851	29,007,184	31,341,341	30,841,777	33,247,743	34,385,158	36,176,522	36,227,956	35,419,992	31,860,089	30,638,814	31,424,237	390,899,664	
# Meters	*156*	*157*	*158*	*162*	*163*	*163*	*163*	*163*	*165*	*166*	*166*	*165*		*162*
Average kWh	194,416	184,759	198,363	190,381	203,974	210,952	221,942	222,257	214,667	191,928	184,571	190,450	2,408,660	200,722


C&I Interruptible (Rate 70) Average Monthly kWh Usage
170,000
160,000
150,000
140,000
130,000
120,000
110,000
100,000
164,620
163,072
156,129
150,227
146,404
144,930
140,290
137,516
Add'l MN Zoo accts addd in June 2010
135,000 B
2011
2012
2013
2014
2015
2016
2017
2018

Dakota Electric Association
Partial Interruptible Service - Rate 71

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Monthly Average
2018														
kWh	1,775,480	1,639,288	1,719,928	1,928,576	2,519,360	2,389,864	2,444,376	2,528,544	2,408,936	2,396,088	2,001,656	1,777,448	25,529,544	
# Consumers	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*27*	*27*	*27*	*27*		*27*
Average kWh	68,288	63,050	66,151	71,429	93,310	88,513	90,532	93,650	89,220	88,744	74,135	65,831	952,853	79,404
2017														
kWh	1,646,936	1,571,864	1,782,696	1,772,384	2,153,960	2,174,848	2,050,176	2,226,456	2,137,072	2,239,328	1,968,488	1,701,992	23,426,200	
# Consumers	*24*	*24*	*24*	*25*	*25*	*25*	*25*	*25*	*25*	*26*	*26*	*26*		*25*
Average kWh	68,622	65,494	74,279	70,895	86,158	86,994	82,007	89,058	85,483	86,128	75,711	65,461	936,290	78,024
2016														
kWh	1,698,200	1,524,608	1,758,424	1,880,872	2,133,000	1,997,752	2,091,584	2,214,848	2,104,688	1,931,400	1,818,128	1,528,040	22,681,544	
# Consumers	*23*	*23*	*23*	*24*	*24*	*24*	*24*	*24*	*24*	*24*	*24*	*24*		*24*
Average kWh	73,835	66,287	76,453	78,370	88,875	83,240	87,149	92,285	87,695	80,475	75,755	63,668	954,087	79,507
2015														
kWh	1,564,752	1,526,176	1,668,656	1,884,104	2,034,432	1,856,872	2,075,352	2,271,640	2,382,232	2,355,400	1,636,216	1,635,336	22,891,168	
# Consumers	*25*	*25*	*25*	*24*	*24*	*24*	*24*	*24*	*24*	*24*	*24*	*23*		*24*
Average kWh	62,590	61,047	66,746	78,504	84,768	77,370	86,473	94,652	99,260	98,142	68,176	71,102	948,830	79,069
2014														
kWh	1,525,824	1,532,888	1,705,680	1,961,008	2,331,288	2,233,080	2,352,152	2,402,616	2,591,904	2,643,880	1,845,144	1,657,128	24,782,592	
# Consumers	*27*	*27*	*26*	*26*	*26*	*26*	*26*	*27*	*27*	*27*	*26*	*26*		*26*
Average kWh	56,512	56,774	65,603	75,423	89,665	85,888	90,467	88,986	95,996	97,921	70,967	63,736	937,938	78,162
2013														
kWh	1,568,632	1,405,464	1,533,624	1,820,616	2,280,720	2,230,984	2,329,192	2,429,008	2,609,176	2,538,040	1,849,752	1,510,136	24,105,344	
# Consumers	*27*	*27*	*27*	*27*	*26*	*27*	*25*	*27*	*27*	*27*	*27*	*27*		*27*
Average kWh	58,097	52,054	56,801	67,430	87,720	82,629	93,168	89,963	96,636	94,001	68,509	55,931	902,939	75,245
2012														
kWh	1,478,448	1,467,504	1,488,000	1,802,112	2,075,680	2,147,874	2,089,684	2,161,430	2,251,860	2,210,408	1,703,104	1,426,480	22,302,584	
# Consumers	*24*	*24*	*25*	*27*	*27*	*27*	*27*	*27*	*27*	*27*	*27*	*27*		*26*
Average kWh	61,602	61,146	59,520	66,745	76,877	79,551	77,396	80,053	83,402	81,867	63,078	52,833	844,070	70,339
2011														
kWh	1,360,912	1,324,376	1,703,136	1,464,768	1,519,608	1,848,288	1,925,872	1,919,680	2,048,656	2,071,400	1,550,336	1,398,720	20,135,752	
# Consumers	*20*	*21*	*21*	*21*	*25*	*25*	*25*	*25*	*25*	*25*	*24*	*24*		*23*
Average kWh	68,046	63,066	81,102	69,751	60,784	73,932	77,035	76,787	81,946	82,856	64,597	58,280	858,182	71,515
2010														
kWh	1,722,296	1,564,080	1,732,608	1,856,960	2,186,120	2,156,048	2,147,408	2,182,416	2,106,720	1,714,248	1,329,968	1,240,240	21,939,112	
# Consumers	*21*	*21*	*21*	*21*	*21*	*20*	*20*	*20*	*20*	*19*	*19*	*20*		*20*
Average kWh	82,014	74,480	82,505	88,427	104,101	107,802	107,370	109,121	105,336	90,224	69,998	62,012	1,083,390	90,283
2009														
kWh	1,780,984	1,541,928	1,751,416	1,752,008	2,108,904	2,207,280	2,159,232	2,138,160	2,246,104	2,070,696	1,711,936	1,715,920	23,184,568	
# Consumers	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*21*	*21*	*21*		*22*
Average kWh	80,954	70,088	79,610	79,637	95,859	100,331	98,147	97,189	102,096	98,605	81,521	81,710	1,065,747	88,812


C&I Interruptible (Rate 71) Average Monthly kWh Usage
Add'l MN Zoo accts added in June 2010
82,500 T
100,000
95,000
90,000
85,000
80,000
75,000
70,000
65,000
60,000
55,000
50,000
71,515
70,339
75,245
78,162
79,069
79,507
78,024
79,404
2011
2012
2013
2014
2015
2016
2017
2018

Workpaper 12
Monthly Billed Sales 2009 - 2018

Dakota Electric Association
Full Year and Monthly Billed Sales 2014 - 2018

Enclosed are schedules detailing the full year and monthly billed sales by rate class for 2014-2018. This data was downloaded monthly from the AS400 software to Excel spreadsheets for 2014 – February 2018. Beginning in March 2018 the data was downloaded from the new UMAX software.

Dakota Electric Association

SALES BY RATE (Billed)

Full Year 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**ADJUSTED REVENUE**
63100	31 Residential	860,418,633	-	860,418,633	90,729,323	-	-	9,167,458	11,352,962	(74,532)	111,175,210
63200	32 Resl Dem Ctrl	428,951	-	428,951	27,796	1,093	10,999	1,977	5,662	-	46,433
63133	33 Resid Electric Vehicles	41,745	-	41,745	2,957	-	-	-	551	-	3,508
63036	36 Irrigation	291,601	-	291,601	13,901	3,143	58,855	2,597	3,791	-	79,144
63039	39 Irrigation	8,295,302	-	8,295,302	395,437	67,095	271,736	105,591	50,602	-	823,365
64100	41 Sm Genl Serv	48,251,732	65,989	48,185,743	4,952,878	-	-	523,843	630,500	(348)	6,106,873
62441-6244:	44(1-3) Street Lights	9,676,063	-	9,676,063	1,700,662	-	-	-	136,357	-	1,837,019
62440	44 Security Lgts	728,226	-	728,226	148,133	-	-	-	9,980	-	158,114
64500	45 Emergency Unmet.	-	-	-	5,184	-	-	-	-	-	5,184
64600	46 General Service	442,409,813	2,239,488	440,170,325	27,082,477	1,388,480	13,199,250	818,853	5,721,723	(2,272)	46,820,032
63047	47 Municipal	-	-	-	3,900	-	-	-	-	-	3,900
64690	49 Geotherm Heat Pump	249,023	-	249,023	14,941	-	-	-	6,226	-	21,167
63151	51 Resid Energy Stg.*	9,449,794	-	9,449,794	377,363	-	-	-	22,416	262	400,041
64151	51 Commer Energy Stg. *	158,261	-	158,261	6,330	-	-	-	-	380	6,710
63152	52 Resid Interruptible*	46,736,444	-	46,736,444	2,243,993	-	-	-	234,019	522	2,478,534
64152	52 Commer Interruptible *	1,317,058	-	1,317,058	63,219	-	-	-	7	6,586	69,812
63900	Resid-Wellspring *	6,367,200	-	6,367,200	25,469	-	-	-	-	-	25,469
64900	Comm-Wellspring *	2,684,200	-	2,684,200	10,737	-	-	-	-	-	10,737
63530	53 Time of Day	205,826	-	205,826	20,127	-	-	2,245	2,717	(144)	24,945
64540	54 Time of Use	3,521,760	-	3,521,760	154,894	15,996	122,011	2,640	45,783	-	325,328
64660	60 Standby Service	17,856	-	17,856	4,065	322	2,790	52,328	232	-	59,414
64700	70 Full Interruptable	388,093,728	-	388,093,728	17,070,016	876,840	3,772,622	213,424	2,328,562	(8,399)	23,376,226
64701	71 Partial Interruptable	24,782,592	-	24,782,592	1,084,026	111,047	576,649	27,135	148,696	(887)	1,835,618
63181	81 Cycled Air M*	4,023,645	-	4,023,645	(120,709)	-	-	-	-	-	(120,709)
63182	82&84 Cycled Air UM	-	-	-	(1,386,675)	-	-	-	-	-	(1,386,675)
	Total	**1,845,074,408**	**2,305,477**	**1,842,768,931**	**$ 144,630,443**	**2,464,015**	**$ 18,014,911**	**$ 10,918,091**	**$ 20,700,786**	**$ (78,833)**	**194,185,398**

*Note: kWh Sales total does not foot since rate 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

January, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	81,266,833		81,266,833	$ 8,243,070	-	$ -	$ 762,671	$ 1,072,127	$ (6,169)	**10,071,699**
63200	32 Resl Dem Ctrl	63,117		63,117	$ 4,090	118	$ 1,098	$ 165	$ 833	$ -	**6,186**
63133	33 Resid Electric Vehicles	3,389		3,389	$ 247	-	$ -	$ -	$ 45	$ -	**291**
63036	36 Irrigation	508		508	$ 24	1	$ 28	$ 216	$ 7	$ -	**275**
63037	37 Irrigation	5,578		5,578	$ 266	12	$ 49	$ 8,751	$ 34	$ -	**9,100**
64100	41 Sm Genl Serv	5,057,303	12,020	5,045,283	$ 503,625	-	$ -	$ 44,078	$ 66,076	$ 43	**613,821**
62441-6244:	44(1-3) Street Lights	804,793		804,793	$ 141,481.39	-	$ -	$ -	$ 11,344	$ -	**152,826**
62440	44 Security Lgts	61,326		61,326	$ 12,325	-	$ -	$ -	$ 834	$ -	**13,159**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	39,605,076	346,080	39,258,996	$ 2,386,916	106,172	$ 918,078	$ 66,521	$ 510,445	$ (192)	**3,881,769**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	30,729		30,729	$ 1,844	-	$ -	$ -	$ 768	$ -	**2,612**
63151	51 Resid Energy Stg.	1,041,087		1,041,087	$ 41,643	-	$ -	$ -	$ 2,465	$ 33	**44,141**
64151	51 Commer Energy Stg.	30,038		30,038	$ 1,202	-	$ -	$ -	$ -	$ 72	**1,274**
63152	52 Resid Interruptible	5,388,162		5,388,162	$ 258,632	-	$ -	$ -	$ 26,981	$ 57	**285,669**
64152	52 Commer Interruptible	206,620		206,620	$ 9,918	-	$ -	$ -	$ 2	$ 1,033	**10,953**
63900	Resid-Wellspring *	547,200		547,200	$ 2,189	-	$ -	$ -	$ -	$ -	**2,189**
64900	Comm-Wellspring *	308,300		308,300	$ 1,233	-	$ -	$ -	$ -	$ -	**1,233**
63530	53 Time of Day	23,523		23,523	$ 2,281	-	$ -	$ 187	$ 311	$ (12)	**2,766**
64540	54 Time of Use	265,296		265,296	$ 11,657	1,233	$ 10,087	$ 240	$ 3,449	$ -	**25,433**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,870	$ -	$ -	**4,870**
64700	70 Full Interruptable	31,411,957		31,411,957	$ 1,377,397	65,112	$ 279,982	$ 17,366	$ 188,472	$ (651)	**1,862,566**
64701	71 Partial Interruptable	1,525,824		1,525,824	$ 66,643	5,478	$ 30,901	$ 2,308	$ 9,155	$ (75)	**108,932**
63181	81 Cycled Air M*	940		940	$ (28)	-	$ -	$ -	$ -	$ -	**(28)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**166,791,159**	**358,100**	**166,433,059**	**$ 13,067,411**	**178,126**	**$ 1,240,223**	**$ 907,373**	**$ 1,893,346**	**$ (5,861)**	17,102,493

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

February, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	81,293,514		81,293,514	$ 8,243,865	-	$ -	$ 764,336	$ 1,072,557	$ (6,213)	**10,074,545**
63200	32 Resl Dem Ctrl	71,205		71,205	$ 4,614	113	$ 1,054	$ 165	$ 940	$ -	**6,773**
63133	33 Resid Electric Vehicles	2,829		2,829	$ 210	-	$ -	$ -	$ 37	$ -	**247**
63036	36 Irrigation	487		487	$ 23	0	$ 7	$ 216	$ 6	$ -	**253**
63037	37 Irrigation	5,138		5,138	$ 245	4	$ 15	$ 8,626	$ 31	$ -	**8,917**
64100	41 Sm Genl Serv	4,877,528	8,036	4,869,492	$ 483,236	-	$ -	$ 44,165	$ 63,728	$ 36	**591,166**
62441-6244	44(1-3) Street Lights	805,300		805,300	$ 141,569.12	-	$ -	$ -	$ 11,351	$ -	**152,920**
62440	44 Security Lgts	61,338		61,338	$ 12,324	-	$ -	$ -	$ 834	$ -	**13,158**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	36,488,260	337,728	36,150,532	$ 2,210,145	102,991	$ 890,872	$ 66,919	$ 469,862	$ (192)	**3,637,608**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	29,764		29,764	$ 1,786	-	$ -	$ -	$ 744	$ -	**2,530**
63151	51 Resid Energy Stg.	1,123,211		1,123,211	$ 44,556	-	$ -	$ -	$ 2,654	$ 42	**47,251**
64151	51 Commer Energy Stg.	22,289		22,289	$ 892	-	$ -	$ -	$ -	$ 53	**945**
63152	52 Resid Interruptible	5,923,677		5,923,677	$ 285,664	-	$ -	$ -	$ 29,633	$ 73	**315,370**
64152	52 Commer Interruptible	230,337		230,337	$ 11,056	-	$ -	$ -	$ 2	$ 1,152	**12,210**
63900	Resid-Wellspring *	552,400		552,400	$ 2,210	-	$ -	$ -	$ -	$ -	**2,210**
64900	Comm-Wellspring *	279,100		279,100	$ 1,116	-	$ -	$ -	$ -	$ -	**1,116**
63530	53 Time of Day	25,763		25,763	$ 2,466	-	$ -	$ 188	$ 340	$ (12)	**2,982**
64540	54 Time of Use	291,408		291,408	$ 12,804	1,101	$ 7,371	$ 240	$ 3,788	$ -	**24,204**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,870	$ -	$ -	**4,870**
64700	70 Full Interruptable	28,694,262		28,694,262	$ 1,257,852	65,933	$ 283,510	$ 17,528	$ 172,166	$ (640)	**1,730,415**
64701	71 Partial Interruptable	1,532,888		1,532,888	$ 66,980	6,201	$ 35,238	$ 2,308	$ 9,197	$ (75)	**113,650**
63181	81 Cycled Air M*	249		249	$ (7)	-	$ -	$ -	$ -	$ -	**(7)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**161,479,198**	**345,764**	**161,133,434**	**$ 12,784,363**	**176,342**	**$ 1,218,068**	**$ 909,562**	**$ 1,837,872**	**$ (5,776)**	**16,744,089**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

March, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	70,218,400		70,218,400	$ 7,120,868	-	$ -	$ 762,595	$ 926,370	$ (6,211)	**8,803,622**
63200	32 Resl Dem Ctrl	64,807		64,807	$ 4,200	133	$ 1,233	$ 171	$ 855	$ -	**6,459**
63133	33 Resid Electric Vehicles	2,866		2,866	$ 195	-	$ -	$ -	$ 38	$ -	**233**
63036	36 Irrigation	525		525	$ 25	0	$ 5	$ 216	$ 7	$ -	**253**
63037	37 Irrigation	4,816		4,816	$ 230	10	$ 42	$ 8,616	$ 29	$ -	**8,917**
64100	41 Sm Genl Serv	4,586,512	7,559	4,578,953	$ 456,631	-	$ -	$ 44,124	$ 59,944	$ 12	**560,711**
62441-6244	44(1-3) Street Lights	805,536		805,536	$ 141,617.83	-	$ -	$ -	$ 11,355	$ -	**152,973**
62440	44 Security Lgts	61,076		61,076	$ 12,283	-	$ -	$ -	$ 830	$ -	**13,114**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	35,680,165	273,696	35,406,469	$ 2,163,891	101,299	$ 876,233	$ 66,997	$ 460,194	$ (192)	**3,567,122**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	25,826		25,826	$ 1,550	-	$ -	$ -	$ 646	$ -	**2,195**
63151	51 Resid Energy Stg.	1,034,110		1,034,110	$ 41,364	-	$ -	$ -	$ 2,448	$ 34	**43,846**
64151	51 Commer Energy Stg.	19,861		19,861	$ 794	-	$ -	$ -	$ -	$ 48	**842**
63152	52 Resid Interruptible	5,129,686		5,129,686	$ 246,225	-	$ -	$ -	$ 25,696	$ 64	**271,984**
64152	52 Commer Interruptible	174,934		174,934	$ 8,397	-	$ -	$ -	$ 1	$ 875	**9,273**
63900	Resid-Wellspring *	533,500		533,500	$ 2,134	-	$ -	$ -	$ -	$ -	**2,134**
64900	Comm-Wellspring *	253,300		253,300	$ 1,013	-	$ -	$ -	$ -	$ -	**1,013**
63530	53 Time of Day	21,580		21,580	$ 2,075	-	$ -	$ 187	$ 285	$ (12)	**2,535**
64540	54 Time of Use	302,112		302,112	$ 13,275	1,832	$ 12,500	$ 240	$ 3,927	$ -	**29,943**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,250	$ -	$ -	**4,250**
64700	70 Full Interruptable	30,687,893		30,687,893	$ 1,344,925	66,345	$ 285,286	$ 17,445	$ 184,127	$ (651)	**1,831,131**
64701	71 Partial Interruptable	1,705,680		1,705,680	$ 74,584	6,223	$ 31,221	$ 2,219	$ 10,234	$ (75)	**118,184**
63181	81 Cycled Air M*	221		221	$ (7)	-	$ -	$ -	$ -	$ -	**(7)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**150,526,385**	**281,255**	**150,245,130**	**$ 11,637,026**	**175,843**	**$ 1,206,521**	**$ 907,059**	**$ 1,686,987**	**$ (6,108)**	**15,431,485**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

April, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW						TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	58,615,247		58,615,247	$ 5,944,312	-	$ -	$ 766,301	$ 773,385	$ (6,177)	**7,477,822**
63200	32 Resl Dem Ctrl	38,863		38,863	$ 2,518	94	$ 870	$ 156	$ 513	$ -	**4,057**
63133	33 Resid Electric Vehicles	2,295		2,295	$ 158	-	$ -	$ -	$ 30	$ -	**188**
63036	36 Irrigation	3,459		3,459	$ 165	31	$ 435	$ 216	$ 45	$ -	**861**
63037	37 Irrigation	11,410		11,410	$ 544	762	$ 3,086	$ 8,682	$ 70	$ -	**12,381**
64100	41 Sm Genl Serv	3,853,728	5,530	3,848,198	$ 383,782	-	$ -	$ 44,317	$ 50,399	$ (37)	**478,461**
62441-6244	44(1-3) Street Lights	805,864		805,864	$ 141,669.41	-	$ -	$ -	$ 11,359	$ -	**153,029**
62440	44 Security Lgts	61,421		61,421	$ 12,351	-	$ -	$ -	$ 835	$ -	**13,187**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	31,877,326	169,536	31,707,790	$ 1,964,404	104,053	$ 900,060	$ 67,131	$ 412,136	$ (192)	**3,343,539**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	20,366		20,366	$ 1,222	-	$ -	$ -	$ 509	$ -	**1,731**
63151	51 Resid Energy Stg.	826,902		826,902	$ 33,076	-	$ -	$ -	$ 1,963	$ 21	**35,061**
64151	51 Commer Energy Stg.	12,952		12,952	$ 518	-	$ -	$ -	$ -	$ 31	**549**
63152	52 Resid Interruptible	4,118,829		4,118,829	$ 198,058	-	$ -	$ -	$ 20,632	$ 38	**218,728**
64152	52 Commer Interruptible	113,593		113,593	$ 5,452	-	$ -	$ -	$ 0	$ 568	**6,021**
63900	Resid-Wellspring *	520,300		520,300	$ 2,081	-	$ -	$ -	$ -	$ -	**2,081**
64900	Comm-Wellspring *	132,800		132,800	$ 531	-	$ -	$ -	$ -	$ -	**531**
63530	53 Time of Day	15,123		15,123	$ 1,441	-	$ -	$ 191	$ 200	$ (12)	**1,820**
64540	54 Time of Use	339,312		339,312	$ 14,909	1,824	$ 11,812	$ 240	$ 4,411	$ -	**31,372**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,250	$ -	$ -	**4,250**
64700	70 Full Interruptable	29,948,653		29,948,653	$ 1,311,248	68,078	$ 292,734	$ 17,365	$ 179,692	$ (697)	**1,800,342**
64701	71 Partial Interruptable	1,961,008		1,961,008	$ 85,780	9,215	$ 44,204	$ 2,219	$ 11,766	$ (75)	**143,894**
63181	81 Cycled Air M*	845		845	$ (25)	-	$ -	$ -	$ -	$ -	**(25)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**132,626,351**	**175,066**	**132,451,285**	**$ 10,104,953**	**184,056**	**$ 1,253,201**	**$ 911,068**	**$ 1,467,946**	**$ (6,531)**	**13,730,637**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

May, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	58,968,076		58,968,076	$ 5,981,425	-	$ -	$ 764,259	$ 778,209	$ (6,342)	**7,517,550**
63200	32 Resl Dem Ctrl	31,184		31,184	$ 2,021	93	$ 864	$ 165	$ 412	$ -	**3,461**
63133	33 Resid Electric Vehicles	3,069		3,069	$ 206	-	$ -	$ -	$ 41	$ -	**246**
63036	36 Irrigation	22,881		22,881	$ 1,091	391	$ 5,470	$ 216	$ 297	$ -	**7,074**
63037	37 Irrigation	79,471		79,471	$ 3,788	3,211	$ 13,004	$ 8,745	$ 485	$ -	**26,022**
64100	41 Sm Genl Serv	3,795,496	3,194	3,792,302	$ 372,675	-	$ -	$ 43,988	$ 49,653	$ (55)	**466,261**
62441-6244	44(1-3) Street Lights	806,280		806,280	$ 141,732.66	-	$ -	$ -	$ 11,365	$ -	**153,098**
62440	44 Security Lgts	61,596		61,596	$ 12,391	-	$ -	$ -	$ 838	$ -	**13,228**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	34,107,259	109,056	33,998,203	$ 2,091,270	108,896	$ 941,947	$ 67,299	$ 441,940	$ (190)	**3,542,266**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	17,831		17,831	$ 1,070	-	$ -	$ -	$ 446	$ -	**1,516**
63151	51 Resid Energy Stg.	706,903		706,903	$ 28,276	-	$ -	$ -	$ 1,678	$ 19	**29,973**
64151	51 Commer Energy Stg.	10,618		10,618	$ 425	-	$ -	$ -	$ -	$ 26	**450**
63152	52 Resid Interruptible	3,297,776		3,297,776	$ 158,293	-	$ -	$ -	$ 16,479	$ 31	**174,804**
64152	52 Commer Interruptible	67,938		67,938	$ 3,261	-	$ -	$ -	$ 0	$ 340	**3,601**
63900	Resid-Wellspring *	517,700		517,700	$ 2,071	-	$ -	$ -	$ -	$ -	**2,071**
64900	Comm-Wellspring *	128,300		128,300	$ 513	-	$ -	$ -	$ -	$ -	**513**
63530	53 Time of Day	14,100		14,100	$ 1,360	-	$ -	$ 183	$ 186	$ (12)	**1,718**
64540	54 Time of Use	374,976		374,976	$ 16,478	1,493	$ 8,826	$ 240	$ 4,875	$ -	**30,418**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,250	$ -	$ -	**4,250**
64700	70 Full Interruptable	32,970,645		32,970,645	$ 1,445,209	80,144	$ 344,619	$ 17,525	$ 197,824	$ (770)	**2,004,406**
64701	71 Partial Interruptable	2,331,288		2,331,288	$ 102,035	10,762	$ 52,723	$ 2,219	$ 13,988	$ (75)	**170,890**
63181	81 Cycled Air M*	142,465		142,465	$ (4,274)	-	$ -	$ -	$ -	$ -	**(4,274)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**137,667,387**	**112,250**	**137,555,137**	**$ 10,362,072**	**204,989**	**$ 1,367,453**	**$ 909,089**	**$ 1,518,714**	**$ (7,029)**	**14,150,299**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

June, 2014

(Accounting Month information downloaded from Orcom)

		kWh				**KW**						**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	65,308,495		65,308,495	$ 7,158,341	-	$ -	$ 762,218	$ 861,855	$ (6,193)	**8,776,222**
63200	32 Resl Dem Ctrl	17,670		17,670	$ 1,145	66	$ 762	$ 165	$ 233	$ -	**2,305**
63133	33 Resid Electric Vehicles	2,629		2,629	$ 176	-	$ -	$ -	$ 35	$ -	**211**
63036	36 Irrigation	33,177		33,177	$ 1,582	394	$ 9,384	$ 216	$ 431	$ -	**11,613**
63037	37 Irrigation	172,396		172,396	$ 8,218	5,621	$ 22,763	$ 8,774	$ 1,052	$ -	**40,808**
64100	41 Sm Genl Serv	3,660,862	3,102	3,657,760	$ 408,035	-	$ -	$ 43,683	$ 47,912	$ (68)	**499,562**
62441-6244	44(1-3) Street Lights	804,893		804,893	$ 141,565.40	-	$ -	$ -	$ 11,346	$ -	**152,911**
62440	44 Security Lgts	61,494		61,494	$ 12,385	-	$ -	$ -	$ 836	$ -	**13,221**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	37,237,992	100,800	37,137,192	$ 2,301,467	126,252	$ 1,465,384	$ 68,039	$ 482,751	$ (188)	**4,317,453**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	14,124		14,124	$ 847	-	$ -	$ -	$ 353	$ -	**1,201**
63151	51 Resid Energy Stg.	629,532		629,532	$ 25,181	-	$ -	$ -	$ 1,499	$ 11	**26,692**
64151	51 Commer Energy Stg.	9,342		9,342	$ 374	-	$ -	$ -	$ -	$ 22	**396**
63152	52 Resid Interruptible	2,838,389		2,838,389	$ 135,963	-	$ -	$ -	$ 14,181	$ 28	**150,171**
64152	52 Commer Interruptible	56,622		56,622	$ 2,718	-	$ -	$ -	$ -	$ 283	**3,001**
63900	Resid-Wellspring *	520,800		520,800	$ 2,083	-	$ -	$ -	$ -	$ -	**2,083**
64900	Comm-Wellspring *	129,100		129,100	$ 516	-	$ -	$ -	$ -	$ -	**516**
63530	53 Time of Day	12,400		12,400	$ 1,236	-	$ -	$ 187	$ 164	$ (12)	**1,575**
64540	54 Time of Use	417,456		417,456	$ 18,406	2,036	$ 19,780	$ 240	$ 5,427	$ -	**43,853**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,480	$ -	$ -	**5,480**
64700	70 Full Interruptable	34,847,029		34,847,029	$ 1,526,490	80,706	$ 347,485	$ 17,463	$ 209,082	$ (761)	**2,099,760**
64701	71 Partial Interruptable	2,233,080		2,233,080	$ 97,726	10,873	$ 58,781	$ 2,219	$ 13,398	$ (73)	**172,052**
63181	81 Cycled Air M*	465,067		465,067	$ (13,952)	-	$ -	$ -	$ -	$ -	**(13,952)**
63182	82&84 Cycled Air UM	-		-	$ (460,562)	-	$ -	$ -	$ -	$ -	**(460,562)**
	Total*	**148,357,582**	**103,902**	**148,253,680**	**$ 11,370,697**	**225,948**	**$ 1,924,339**	**$ 908,685**	**$ 1,650,555**	**$ (6,949)**	15,847,327

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

July, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	79,204,435		79,204,435	$ 9,143,234	-	$ -	$ 763,232	$ 1,045,277	$ (6,179)	**10,945,564**
63200	32 Resl Dem Ctrl	17,921		17,921	$ 1,161	83	$ 1,076	$ 165	$ 237	$ -	**2,639**
63133	33 Resid Electric Vehicles	3,173		3,173	$ 210	-	$ -	$ -	$ 42	$ -	**252**
63036	36 Irrigation	66,283		66,283	$ 3,160	589	$ 14,018	$ 216	$ 862	$ -	**18,256**
63037	37 Irrigation	2,374,297		2,374,297	$ 113,183	21,895	$ 88,673	$ 8,872	$ 14,483	$ -	**225,211**
64100	41 Sm Genl Serv	3,711,052	2,774	3,708,278	$ 421,567	-	$ -	$ 43,286	$ 48,579	$ (75)	**513,357**
62441-6244	44(1-3) Street Lights	807,120		807,120	$ 141,909.30	-	$ -	$ -	$ 11,377	$ -	**153,286**
62440	44 Security Lgts	61,585		61,585	$ 12,532	-	$ -	$ -	$ 838	$ -	**13,369**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	40,149,274	104,640	40,044,634	$ 2,457,016	126,788	$ 1,489,763	$ 68,311	$ 520,578	$ (188)	**4,535,480**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	17,159		17,159	$ 1,030	-	$ -	$ -	$ 429	$ -	**1,459**
63151	51 Resid Energy Stg.	696,884		696,884	$ 27,875	-	$ -	$ -	$ 1,662	$ 11	**29,548**
64151	51 Commer Energy Stg.	7,503		7,503	$ 300	-	$ -	$ -	$ -	$ 18	**318**
63152	52 Resid Interruptible	3,229,482		3,229,482	$ 154,969	-	$ -	$ -	$ 16,133	$ 34	**171,136**
64152	52 Commer Interruptible	63,338		63,338	$ 3,040	-	$ -	$ -	$ -	$ 317	**3,357**
63900	Resid-Wellspring *	535,200		535,200	$ 2,141	-	$ -	$ -	$ -	$ -	**2,141**
64900	Comm-Wellspring *	127,800		127,800	$ 511	-	$ -	$ -	$ -	$ -	**511**
63530	53 Time of Day	14,882		14,882	$ 1,499	-	$ -	$ 187	$ 196	$ (12)	**1,871**
64540	54 Time of Use	507,312		507,312	$ 22,348	2,070	$ 17,928	$ 240	$ 6,595	$ -	**47,112**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,480	$ -	$ -	**5,480**
64700	70 Full Interruptable	35,811,446		35,811,446	$ 1,618,617	82,612	$ 356,762	$ 17,689	$ 214,869	$ (788)	**2,207,149**
64701	71 Partial Interruptable	2,352,152		2,352,152	$ 102,971	9,907	$ 51,016	$ 2,228	$ 14,113	$ (73)	**170,254**
63181	81 Cycled Air M*	923,819		923,819	$ (27,715)	-	$ -	$ -	$ -	$ -	**(27,715)**
63182	82&84 Cycled Air UM	-		-	$ (462,782)	-	$ -	$ -	$ -	$ -	**(462,782)**
	Total*	**169,095,298**	**107,414**	**168,987,884**	**$ 13,739,534**	**243,944**	**$ 2,019,237**	**$ 909,906**	**$ 1,896,269**	**$ (6,936)**	**18,558,009**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

August, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	87,185,005		87,185,005	$ 10,063,909	-	$ -	$ 763,062	$ 1,150,445	$ (6,279)	**11,971,137**
63200	32 Resl Dem Ctrl	18,110		18,110	$ 1,174	74	$ 948	$ 165	$ 239	$ -	**2,526**
63133	33 Resid Electric Vehicles	3,739		3,739	$ 280	-	$ -	$ -	$ 49	$ -	**329**
63036	36 Irrigation	81,212		81,212	$ 3,871	529	$ 12,594	$ 221	$ 1,056	$ -	**17,742**
63037	37 Irrigation	5,157,107		5,157,107	$ 245,839	23,536	$ 95,322	$ 8,886	$ 31,458	$ -	**381,506**
64100	41 Sm Genl Serv	3,908,649	2,610	3,906,039	$ 444,020	-	$ -	$ 43,156	$ 51,165	$ (73)	**538,268**
62441-6244	44(1-3) Street Lights	804,496		804,496	$ 141,454.09	-	$ -	$ -	$ 11,340	$ -	**152,794**
62440	44 Security Lgts	61,619		61,619	$ 12,427	-	$ -	$ -	$ 838	$ -	**13,265**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	42,593,421	108,960	42,484,461	$ 2,603,775	130,704	$ 1,535,771	$ 69,384	$ 552,288	$ (192)	**4,761,026**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	19,312		19,312	$ 1,159	-	$ -	$ -	$ 483	$ -	**1,642**
63151	51 Resid Energy Stg.	740,760		740,760	$ 29,572	-	$ -	$ -	$ 1,765	$ 13	**31,350**
64151	51 Commer Energy Stg.	8,716		8,716	$ 349	-	$ -	$ -	$ -	$ 21	**370**
63152	52 Resid Interruptible	3,601,143		3,601,143	$ 172,855	-	$ -	$ -	$ 18,040	$ 42	**190,937**
64152	52 Commer Interruptible	72,979		72,979	$ 3,503	-	$ -	$ -	$ -	$ 365	**3,868**
63900	Resid-Wellspring *	543,100		543,100	$ 2,172	-	$ -	$ -	$ -	$ -	**2,172**
64900	Comm-Wellspring *	131,800		131,800	$ 527	-	$ -	$ -	$ -	$ -	**527**
63530	53 Time of Day	14,752		14,752	$ 1,498	-	$ -	$ 187	$ 195	$ (12)	**1,868**
64540	54 Time of Use	711,216		711,216	$ 31,251	2,297	$ 20,218	$ 240	$ 9,246	$ -	**60,955**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,480	$ -	$ -	**5,480**
64700	70 Full Interruptable	38,071,040		38,071,040	$ 1,678,861	83,202	$ 358,128	$ 17,949	$ 228,426	$ (738)	**2,282,626**
64701	71 Partial Interruptable	2,402,616		2,402,616	$ 105,094	10,324	$ 57,463	$ 2,228	$ 14,416	$ (73)	**179,127**
63181	81 Cycled Air M*	1,177,942		1,177,942	$ (35,338)	-	$ -	$ -	$ -	$ -	**(35,338)**
63182	82&84 Cycled Air UM	-		-	$ (463,283)	-	$ -	$ -	$ -	$ -	**(463,283)**
	Total*	**185,455,892**	**111,570**	**185,344,322**	**$ 15,045,724**	**250,666**	**$ 2,080,445**	**$ 910,958**	**$ 2,071,449**	**$ (6,927)**	**20,101,650**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

September, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	87,228,529		87,228,529	$ 9,444,317	-	$ -	$ 767,290	$ 1,151,155	$ (6,356)	**11,356,405**
63200	32 Resl Dem Ctrl	18,067		18,067	$ 1,171	86	$ 915	$ 165	$ 238	$ -	**2,489**
63133	33 Resid Electric Vehicles	4,133		4,133	$ 292	-	$ -	$ -	$ 55	$ -	**347**
63036	36 Irrigation	55,743		55,743	$ 2,657	540	$ 7,561	$ 216	$ 725	$ -	**11,159**
63037	37 Irrigation	323,450		323,450	$ 15,419	8,725	$ 35,338	$ 8,934	$ 1,973	$ -	**61,664**
64100	41 Sm Genl Serv	3,769,857	3,378	3,766,479	$ 384,104	-	$ -	$ 43,185	$ 49,307	$ (71)	**476,524**
62441-6244	44(1-3) Street Lights	806,288		806,288	$ 141,759.89	-	$ -	$ -	$ 11,365	$ -	**153,125**
62440	44 Security Lgts	60,190		60,190	$ 12,304	-	$ -	$ -	$ 830	$ -	**13,134**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	40,775,073	95,520	40,679,553	$ 2,500,071	130,298	$ 1,144,549	$ 69,587	$ 528,800	$ (187)	**4,242,819**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	16,923		16,923	$ 1,015	-	$ -	$ -	$ 423	$ -	**1,438**
63151	51 Resid Energy Stg.	707,475		707,475	$ 28,204	-	$ -	$ -	$ 1,687	$ 11	**29,902**
64151	51 Commer Energy Stg.	7,971		7,971	$ 319	-	$ -	$ -	$ -	$ 19	**338**
63152	52 Resid Interruptible	3,430,129		3,430,129	$ 164,120	-	$ -	$ -	$ 17,139	$ 38	**181,298**
64152	52 Commer Interruptible	58,988		58,988	$ 2,831	-	$ -	$ -	$ 0	$ 295	**3,126**
63900	Resid-Wellspring *	546,900		546,900	$ 2,188	-	$ -	$ -	$ -	$ -	**2,188**
64900	Comm-Wellspring *	127,300		127,300	$ 509	-	$ -	$ -	$ -	$ -	**509**
63530	53 Time of Day	15,167		15,167	$ 1,512	-	$ -	$ 187	$ 200	$ (12)	**1,887**
64540	54 Time of Use	132,144		132,144	$ 5,833	579	$ 2,566	$ 180	$ 1,718	$ -	**10,296**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,250	$ -	$ -	**4,250**
64700	70 Full Interruptable	33,514,460		33,514,460	$ 1,469,401	81,188	$ 348,988	$ 17,764	$ 201,087	$ (739)	**2,036,501**
64701	71 Partial Interruptable	2,591,904		2,591,904	$ 113,452	12,545	$ 62,460	$ 2,361	$ 15,551	$ (73)	**193,752**
63181	81 Cycled Air M*	1,055,726		1,055,726	$ (31,672)	-	$ -	$ -	$ -	$ -	**(31,672)**
63182	82&84 Cycled Air UM	-		-	$ (48)	-	$ -	$ -	$ -	$ -	**(48)**
	Total*	**173,516,491**	**98,898**	**173,417,593**	**$ 14,260,515**	**233,962**	**$ 1,602,377**	**$ 914,120**	**$ 1,982,254**	**$ (7,076)**	**18,752,190**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

October, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	60,409,634		60,409,634	$ 6,128,717	-	$ -	$ 762,571	$ 797,312	$ (6,137)	**7,682,463**
63200	32 Resl Dem Ctrl	16,985		16,985	$ 1,101	62	$ 581	$ 165	$ 224	$ -	**2,071**
63133	33 Resid Electric Vehicles	3,832		3,832	$ 276	-	$ -	$ -	$ 51	$ -	**326**
63036	36 Irrigation	23,810		23,810	$ 1,135	317	$ 4,443	$ 216	$ 310	$ -	**6,104**
63037	37 Irrigation	136,329		136,329	$ 6,499	2,201	$ 8,914	$ 8,904	$ 832	$ -	**25,148**
64100	41 Sm Genl Serv	3,362,341	3,497	3,358,844	$ 333,703	-	$ -	$ 43,212	$ 43,840	$ (62)	**420,694**
62441-6244	44(1-3) Street Lights	807,374		807,374	$ 141,933.70	-	$ -	$ -	$ 11,381	$ -	**153,314**
62440	44 Security Lgts	59,962		59,962	$ 12,300	-	$ -	$ -	$ 827	$ -	**13,127**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	34,757,837	111,648	34,646,189	$ 2,154,761	123,267	$ 1,066,256	$ 69,345	$ 450,367	$ (188)	**3,740,539**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	15,142		15,142	$ 909	-	$ -	$ -	$ 379	$ -	**1,287**
63151	51 Resid Energy Stg.	475,969		475,969	$ 18,936	-	$ -	$ -	$ 1,129	$ 13	**20,079**
64151	51 Commer Energy Stg.	5,669		5,669	$ 227	-	$ -	$ -	$ -	$ 14	**240**
63152	52 Resid Interruptible	2,219,347		2,219,347	$ 106,343	-	$ -	$ -	$ 11,081	$ 27	**117,451**
64152	52 Commer Interruptible	46,498		46,498	$ 2,232	-	$ -	$ -	$ 0	$ 233	**2,465**
63900	Resid-Wellspring *	514,600		514,600	$ 2,058	-	$ -	$ -	$ -	$ -	**2,058**
64900	Comm-Wellspring *	124,900		124,900	$ 500	-	$ -	$ -	$ -	$ -	**500**
63530	53 Time of Day	12,653		12,653	$ 1,187	-	$ -	$ 187	$ 174	$ (12)	**1,536**
64540	54 Time of Use	96,240		96,240	$ 4,229	648	$ 4,008	$ 180	$ 1,251	$ -	**9,668**
64660	60 Standby Service	17,856		17,856	$ 4,065	322	$ 2,790	$ 28	$ 232	$ -	**7,114**
64700	70 Full Interruptable	31,657,450		31,657,450	$ 1,388,306	72,544	$ 311,861	$ 18,412	$ 189,945	$ (684)	**1,907,840**
64701	71 Partial Interruptable	2,643,880		2,643,880	$ 115,767	11,941	$ 58,423	$ 2,308	$ 15,863	$ (75)	**192,287**
63181	81 Cycled Air M*	232,414		232,414	$ (6,972)	-	$ -	$ -	$ -	$ -	**(6,972)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**136,768,808**	**115,145**	**136,653,663**	**$ 10,418,967**	**211,303**	**$ 1,457,275**	**$ 905,527**	**$ 1,525,196**	**$ (6,871)**	**14,300,094**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

November, 2014

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	per Download
63100	31 Residential	60,469,495		60,469,495	$ 6,131,678	-	$ -	$ 762,725	$ 797,388	$ (6,172)	**7,685,620**
63200	32 Resl Dem Ctrl	24,525		24,525	$ 1,589	65	$ 605	$ 165	$ 324	$ -	**2,683**
63133	33 Resid Electric Vehicles	3,923		3,923	$ 282	-	$ -	$ -	$ 52	$ -	**334**
63036	36 Irrigation	3,214		3,214	$ 153	343	$ 4,805	$ 216	$ 42	$ -	**5,216**
63037	37 Irrigation	20,052		20,052	$ 956	1,029	$ 4,167	$ 8,898	$ 122	$ -	**14,143**
64100	41 Sm Genl Serv	3,596,699	5,431	3,591,268	$ 357,044	-	$ -	$ 43,377	$ 46,881	$ (40)	**447,262**
62441-6244:	44(1-3) Street Lights	807,908		807,908	$ 141,801.13	-	$ -	$ -	$ 11,371	$ -	**153,172**
62440	44 Security Lgts	58,398		58,398	$ 12,270	-	$ -	$ -	$ 822	$ -	**13,091**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	33,624,925	228,864	33,396,061	$ 2,074,912	116,865	$ 1,011,087	$ 69,434	$ 434,087	$ (184)	**3,589,336**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	17,129		17,129	$ 1,028	-	$ -	$ -	$ 428	$ -	**1,456**
63151	51 Resid Energy Stg.	578,231		578,231	$ 23,129	-	$ -	$ -	$ 1,370	$ 17	**24,517**
64151	51 Commer Energy Stg.	7,100		7,100	$ 284	-	$ -	$ -	$ -	$ 17	**301**
63152	52 Resid Interruptible	3,036,146		3,036,146	$ 145,735	-	$ -	$ -	$ 15,388	$ 37	**161,161**
64152	52 Commer Interruptible	81,990		81,990	$ 3,936	-	$ -	$ -	$ 1	$ 410	**4,346**
63900	Resid-Wellspring *	511,500		511,500	$ 2,046	-	$ -	$ -	$ -	$ -	**2,046**
64900	Comm-Wellspring *	566,400		566,400	$ 2,266	-	$ -	$ -	$ -	$ -	**2,266**
63530	53 Time of Day	15,040		15,040	$ 1,496	-	$ -	$ 191	$ 192	$ (12)	**1,867**
64540	54 Time of Use	42,288		42,288	$ 1,858	405	$ 2,541	$ 180	$ 550	$ -	**5,129**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,250	$ -	$ -	**4,250**
64700	70 Full Interruptable	29,780,107		29,780,107	$ 1,305,687	65,739	$ 282,591	$ 18,426	$ 178,681	$ (619)	**1,784,765**
64701	71 Partial Interruptable	1,845,144		1,845,144	$ 80,648	10,824	$ 53,623	$ 2,289	$ 11,071	$ (73)	**147,558**
63181	81 Cycled Air M*	23,771		23,771	$ (713)	-	$ -	$ -	$ -	$ -	**(713)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**134,012,314**	**234,295**	**133,778,019**	**$ 10,288,842**	**195,270**	**$ 1,359,418**	**$ 910,152**	**$ 1,498,768**	**$ (6,619)**	**14,050,561**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

December, 2014

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	70,250,970		70,250,970	$ 7,125,589	-	$ -	$ 766,198	$ 926,882	$ (6,106)	**8,812,562**
63200	32 Resl Dem Ctrl	46,497		46,497	$ 3,013	107	$ 993	$ 165	$ 614	$ -	**4,785**
63133	33 Resid Electric Vehicles	5,868		5,868	$ 426	-	$ -	$ -	$ 77	$ -	**503**
63036	36 Irrigation	302		302	$ 14	5	$ 104	$ 216	$ 4	$ -	**338**
63037	37 Irrigation	5,258		5,258	$ 251	89	$ 360	$ 8,904	$ 32	$ -	**9,547**
64100	41 Sm Genl Serv	4,071,705	8,858	4,062,847	$ 404,456	-	$ -	$ 43,272	$ 53,017	$ 42	**500,787**
62441-6244	44(1-3) Street Lights	810,211		810,211	$ 142,168.53	-	$ -	$ -	$ 11,403	$ -	**153,572**
62440	44 Security Lgts	58,221		58,221	$ 12,243	-	$ -	$ -	$ 819	$ -	**13,062**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	35,513,205	252,960	35,260,245	$ 2,173,850	110,896	$ 959,251	$ 69,886	$ 458,276	$ (187)	**3,661,076**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	24,718		24,718	$ 1,483	-	$ -	$ -	$ 618	$ -	**2,101**
63151	51 Resid Energy Stg.	888,730		888,730	$ 35,549	-	$ -	$ -	$ 2,096	$ 37	**37,682**
64151	51 Commer Energy Stg.	16,202		16,202	$ 648	-	$ -	$ -	$ -	$ 39	**687**
63152	52 Resid Interruptible	4,523,678		4,523,678	$ 217,137	-	$ -	$ -	$ 22,636	$ 54	**239,826**
64152	52 Commer Interruptible	143,221		143,221	$ 6,875	-	$ -	$ -	$ 0	$ 716	**7,591**
63900	Resid-Wellspring *	524,000		524,000	$ 2,096	-	$ -	$ -	$ -	$ -	**2,096**
64900	Comm-Wellspring *	375,100		375,100	$ 1,500	-	$ -	$ -	$ -	$ -	**1,500**
63530	53 Time of Day	20,845		20,845	$ 2,075	-	$ -	$ 182	$ 275	$ (12)	**2,520**
64540	54 Time of Use	42,000		42,000	$ 1,845	479	$ 4,373	$ 180	$ 546	$ -	**6,945**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,870	$ -	$ -	**4,870**
64700	70 Full Interruptable	30,698,786		30,698,786	$ 1,346,022	65,236	$ 280,677	$ 18,492	$ 184,193	$ (660)	**1,828,724**
64701	71 Partial Interruptable	1,657,128		1,657,128	$ 72,346	6,753	$ 40,595	$ 2,228	$ 9,943	$ (73)	**125,039**
63181	81 Cycled Air M*	186		186	$ (6)	-	$ -	$ -	$ -	$ -	**(6)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**148,777,545**	**261,818**	**148,515,727**	**$ 11,550,338**	**183,565**	**$ 1,286,353**	**$ 914,593**	**$ 1,671,431**	**$ (6,150)**	**15,416,565**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

Full Year 2015

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**ADJUSTED**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**REVENUE**
63100	31 Residential	833,090,791	-	833,090,791	88,978,211	-	-	9,320,303	12,184,594	(74,729)	110,408,379
63200	32 Resl Dem Ctrl	385,868	-	385,868	25,409	903	9,212	1,995	5,557	-	42,173
63133	33 Resid Electric Vehicles	77,319	-	77,319	5,466	-	-	-	1,113	-	6,579
63036	36 Irrigation	272,932	-	272,932	11,899	3,303	61,188	2,650	4,261	-	79,999
63039	39 Irrigation	5,820,054	-	5,820,054	277,458	75,984	307,788	111,022	62,801	-	759,069
64100	41 Sm Genl Serv	44,180,089	55,963	44,124,126	4,582,968	-	-	532,005	640,665	(456)	5,755,182
62441-6244:	44(1-3) Street Lights	9,769,462	-	9,769,462	1,725,527	-	-	-	149,821	-	1,875,349
62440	44 Security Lgts	685,595	-	685,595	145,717	-	-	-	10,571	-	156,287
64500	45 Emergency Unmet.	-	-	-	5,292	-	-	-	-	-	5,292
64600	46 General Service	438,018,390	1,989,312	436,029,078	27,166,145	1,384,113	13,219,382	869,615	6,245,257	(9,914)	47,490,486
63047	47 Municipal	-	-	-	3,900	-	-	-	-	-	3,900
64690	49 Geotherm Heat Pump	186,092	-	186,092	11,677	-	-	-	3,442	-	15,119
63151	51 Resid Energy Stg.*	9,096,215	-	9,096,215	366,292	-	-	-	20,128	172	386,592
64151	51 Commer Energy Stg. *	133,660	-	133,660	5,379	-	-	-	86	218	5,682
63152	52 Resid Interruptible*	43,295,811	-	43,295,811	2,101,473	-	-	-	210,127	323	2,311,923
64152	52 Commer Interruptible *	1,103,826	-	1,103,826	53,824	-	-	-	1,685	3,529	59,039
63900	Resid-Wellspring *	6,183,500	-	6,183,500	24,734	-	-	-	-	-	24,734
64900	Comm-Wellspring *	2,218,300	-	2,218,300	8,873	-	-	-	-	-	8,873
63530	53 Time of Day	190,183	-	190,183	18,859	-	-	2,277	2,746	(144)	23,738
64540	54 Time of Use	1,033,680	-	1,033,680	46,609	7,154	53,673	2,196	14,564	-	117,042
64660	60 Standby Service	11,232	-	11,232	3,792	293	2,536	53,598	172	-	60,098
64700	70 Full Interruptable	388,426,267	-	388,426,267	17,237,899	889,993	3,856,316	226,585	3,811,805	(8,330)	25,124,275
64701	71 Partial Interruptable	22,891,168	-	22,891,168	1,010,799	99,523	522,903	25,699	225,803	(856)	1,784,348
63181	81 Cycled Air M*	4,544,843	-	4,544,843	(136,345)	-	-	-	-	-	(136,345)
63182	82&84 Cycled Air UM	-	-	-	(1,407,824)	-	-	-	-	-	(1,407,824)
	Total	**1,798,668,634**	**2,045,275**	**1,796,623,359**	**$ 142,274,034**	**2,461,266**	**$ 18,032,998**	**$ 11,147,945**	**$ 23,595,199**	**$ (90,188)**	**194,959,989**

*Note: kWh Sales total does not foot since rate 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

January, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	75,071,679		75,071,679	$ 7,614,800	-	$ -	$ 766,335	$ 1,170,415	$ (6,040)	**9,545,510**
63200	32 Resl Dem Ctrl	56,799		56,799	$ 3,681	105	$ 973	$ 165	$ 886	$ -	**5,704**
63133	33 Resid Electric Vehicles	5,633		5,633	$ 404	-	$ -	$ -	$ 88	$ -	**492**
63036	36 Irrigation	307		307	$ (1,101)	1	$ 13	$ 216	$ 5	$ -	**(867)**
63037	37 Irrigation	4,747		4,747	$ 226	33	$ 133	$ 8,910	$ 51	$ -	**9,320**
64100	41 Sm Genl Serv	4,526,704	9,720	4,516,984	$ 449,621	-	$ -	$ 43,212	$ 70,214	$ 78	**563,126**
62441-6244:	44(1-3) Street Lights	810,290		810,290	$ 142,182.09	-	$ -	$ -	$ 13,345	$ -	**155,527**
62440	44 Security Lgts	58,154		58,154	$ 12,232	-	$ -	$ -	$ 961	$ -	**13,193**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	38,811,710	314,688	38,497,022	$ 2,325,273	105,817	$ 915,316	$ 70,528	$ 588,887	$ (192)	**3,899,812**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	27,334		27,334	$ 1,640	-	$ -	$ -	$ 538	$ -	**2,179**
63151	51 Resid Energy Stg.	979,267		979,267	$ 39,171	-	$ -	$ -	$ 2,308	$ 42	**41,521**
64151	51 Commer Energy Stg.	19,785		19,785	$ 791	-	$ -	$ -	$ -	$ 47	**839**
63152	52 Resid Interruptible	4,952,163		4,952,163	$ 237,704	-	$ -	$ -	$ 25,761	$ 82	**263,548**
64152	52 Commer Interruptible	178,691		178,691	$ 8,577	-	$ -	$ -	$ 1	$ 929	**9,507**
63900	Resid-Wellspring *	528,600		528,600	$ 2,114	-	$ -	$ -	$ -	$ -	**2,114**
64900	Comm-Wellspring *	299,900		299,900	$ 1,200	-	$ -	$ -	$ -	$ -	**1,200**
63530	53 Time of Day	20,286		20,286	$ 1,939	-	$ -	$ 187	$ 319	$ (12)	**2,433**
64540	54 Time of Use	57,360		57,360	$ 2,520	396	$ 4,018	$ 180	$ 878	$ -	**7,596**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,950	$ -	$ -	**4,950**
64700	70 Full Interruptable	31,018,945		31,018,945	$ 1,359,806	64,919	$ 279,303	$ 18,341	$ 322,597	$ (638)	**1,979,410**
64701	71 Partial Interruptable	1,564,752		1,564,752	$ 68,360	6,001	$ 34,603	$ 2,148	$ 16,273	$ (73)	**121,311**
63181	81 Cycled Air M*	205		205	$ (6)	-	$ -	$ -	$ -	$ -	**(6)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**158,164,606**	**324,408**	**157,840,198**	**$ 12,271,892**	**177,271**	**$ 1,234,360**	**$ 915,172**	**$ 2,213,528**	**$ (5,776)**	**16,629,176**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

February, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	70,877,258		70,877,258	$ 7,188,967	-	$ -	$ 766,333	$ 1,105,022	$ (6,019)	**9,054,304**
63200	32 Resl Dem Ctrl	62,052		62,052	$ 4,021	104	$ 970	$ 165	$ 968	$ -	**6,124**
63133	33 Resid Electric Vehicles	5,779		5,779	$ 399	-	$ -	$ -	$ 90	$ -	**489**
63036	36 Irrigation	264		264	$ 13	1	$ 13	$ 216	$ 4	$ -	**246**
63037	37 Irrigation	4,372		4,372	$ 208	33	$ 134	$ 8,884	$ 47	$ -	**9,273**
64100	41 Sm Genl Serv	4,375,251	8,113	4,367,138	$ 434,548	-	$ -	$ 43,021	$ 67,881	$ 52	**545,502**
62441-6244:	44(1-3) Street Lights	809,777		809,777	$ 142,066.76	-	$ -	$ -	$ 13,337	$ -	**155,404**
62440	44 Security Lgts	58,031		58,031	$ 12,213	-	$ -	$ -	$ 959	$ -	**13,172**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	36,822,102	309,312	36,512,790	$ 2,222,339	103,737	$ 897,321	$ 70,223	$ 558,531	$ (189)	**3,748,225**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	20,116		20,116	$ 1,207	-	$ -	$ -	$ 396	$ -	**1,603**
63151	51 Resid Energy Stg.	998,569		998,569	$ 39,943	-	$ -	$ -	$ 2,358	$ 39	**42,339**
64151	51 Commer Energy Stg.	23,014		23,014	$ 921	-	$ -	$ -	$ -	$ 55	**976**
63152	52 Resid Interruptible	5,095,714		5,095,714	$ 244,395	-	$ -	$ -	$ 26,530	$ 62	**270,987**
64152	52 Commer Interruptible	160,928		160,928	$ 7,725	-	$ -	$ -	$ 1	$ 837	**8,562**
63900	Resid-Wellspring *	528,300		528,300	$ 2,113	-	$ -	$ -	$ -	$ -	**2,113**
64900	Comm-Wellspring *	310,900		310,900	$ 1,244	-	$ -	$ -	$ -	$ -	**1,244**
63530	53 Time of Day	21,604		21,604	$ 2,077	-	$ -	$ 187	$ 337	$ (12)	**2,589**
64540	54 Time of Use	38,112		38,112	$ 1,681	460	$ 4,289	$ 180	$ 583	$ -	**6,733**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,950	$ -	$ -	**4,950**
64700	70 Full Interruptable	28,494,896		28,494,896	$ 1,248,953	64,035	$ 275,489	$ 18,350	$ 296,347	$ (638)	**1,838,501**
64701	71 Partial Interruptable	1,526,176		1,526,176	$ 66,692	5,900	$ 34,399	$ 2,180	$ 15,872	$ (72)	**119,071**
63181	81 Cycled Air M*	942		942	$ (28)	-	$ -	$ -	$ -	$ -	**(28)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**149,394,015**	**317,425**	**149,076,590**	**$ 11,622,452**	**174,269**	**$ 1,212,615**	**$ 914,689**	**$ 2,089,264**	**$ (5,885)**	**15,833,135**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

March, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	66,971,648		66,971,648	$ 6,792,664	-	$ -	$ 768,478	$ 1,044,254	$ (6,252)	**8,599,144**
63200	32 Resl Dem Ctrl	58,682		58,682	$ 3,803	102	$ 950	$ 165	$ 915	$ -	**5,833**
63133	33 Resid Electric Vehicles	7,765		7,765	$ 550	-	$ -	$ -	$ 121	$ -	**671**
63036	36 Irrigation	433		433	$ 21	20	$ 277	$ 216	$ 7	$ -	**520**
63037	37 Irrigation	4,202		4,202	$ 200	(18)	$ (72)	$ 8,894	$ 46	$ -	**9,068**
64100	41 Sm Genl Serv	4,004,897	5,895	3,999,002	$ 397,678	-	$ -	$ 42,875	$ 62,085	$ 75	**502,714**
62441-6244	44(1-3) Street Lights	810,050		810,050	$ 142,119.14	-	$ -	$ -	$ 13,341	$ -	**155,461**
62440	44 Security Lgts	58,128		58,128	$ 12,238	-	$ -	$ -	$ 960	$ -	**13,198**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	33,265,798	223,584	33,042,214	$ 2,040,756	104,878	$ 907,196	$ 70,384	$ 505,495	$ (739)	**3,523,091**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	19,179		19,179	$ 1,151	-	$ -	$ -	$ 378	$ -	**1,529**
63151	51 Resid Energy Stg.	1,003,025		1,003,025	$ 39,922	-	$ -	$ -	$ 2,369	$ 39	**42,329**
64151	51 Commer Energy Stg.	20,196		20,196	$ 808	-	$ -	$ -	$ -	$ 48	**856**
63152	52 Resid Interruptible	4,935,954		4,935,954	$ 236,565	-	$ -	$ -	$ 25,689	$ 80	**262,334**
64152	52 Commer Interruptible	150,310		150,310	$ 7,215	-	$ -	$ -	$ 1	$ 782	**7,997**
63900	Resid-Wellspring *	524,500		524,500	$ 2,098	-	$ -	$ -	$ -	$ -	**2,098**
64900	Comm-Wellspring *	148,500		148,500	$ 594	-	$ -	$ -	$ -	$ -	**594**
63530	53 Time of Day	18,971		18,971	$ 1,828	-	$ -	$ 187	$ 296	$ (12)	**2,298**
64540	54 Time of Use	46,800		46,800	$ 2,117	524	$ 3,522	$ 180	$ 716	$ -	**6,535**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,310	$ -	$ -	**4,310**
64700	70 Full Interruptable	30,869,423		30,869,423	$ 1,353,242	69,080	$ 296,963	$ 18,430	$ 321,042	$ (595)	**1,989,082**
64701	71 Partial Interruptable	1,668,656		1,668,656	$ 72,917	6,271	$ 31,391	$ 2,148	$ 17,354	$ (69)	**123,741**
63181	81 Cycled Air M*	391		391	$ (12)	-	$ -	$ -	$ -	$ -	**(12)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**143,914,117**	**229,479**	**143,684,638**	**$ 11,109,230**	**180,857**	**$ 1,240,227**	**$ 916,266**	**$ 1,995,068**	**$ (6,643)**	**15,254,149**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

April, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	56,306,483		56,306,483	$ 5,711,319	-	$ -	$ 770,009	$ 878,101	$ (6,233)	**7,353,196**
63200	32 Resl Dem Ctrl	35,632		35,632	$ 2,309	77	$ 717	$ 165	$ 556	$ -	**3,747**
63133	33 Resid Electric Vehicles	6,602		6,602	$ 428	-	$ -	$ -	$ 103	$ -	**531**
63036	36 Irrigation	8,584		8,584	$ 409	332	$ 4,654	$ 196	$ 135	$ -	**5,394**
63037	37 Irrigation	39,727		39,727	$ 1,894	1,438	$ 5,825	$ 8,947	$ 429	$ -	**17,095**
64100	41 Sm Genl Serv	3,615,640	4,217	3,611,423	$ 358,880	-	$ -	$ 43,019	$ 56,083	$ 0	**457,983**
62441-6244	44(1-3) Street Lights	809,133		809,133	$ 141,964.78	-	$ -	$ -	$ 13,326	$ -	**155,291**
62440	44 Security Lgts	58,022		58,022	$ 12,225	-	$ -	$ -	$ 959	$ -	**13,184**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	33,904,535	145,344	33,759,191	$ 2,073,012	109,124	$ 943,920	$ 70,833	$ 516,489	$ (1,447)	**3,602,807**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	15,418		15,418	$ 925	-	$ -	$ -	$ 304	$ -	**1,229**
63151	51 Resid Energy Stg.	756,651		756,651	$ 30,266	-	$ -	$ -	$ 1,791	$ 25	**32,082**
64151	51 Commer Energy Stg.	12,005		12,005	$ 480	-	$ -	$ -	$ -	$ 29	**509**
63152	52 Resid Interruptible	3,586,725		3,586,725	$ 171,899	-	$ -	$ -	$ 18,648	$ 41	**190,588**
64152	52 Commer Interruptible	87,687		87,687	$ 4,209	-	$ -	$ -	$ 0	$ 456	**4,665**
63900	Resid-Wellspring *	506,100		506,100	$ 2,024	-	$ -	$ -	$ -	$ -	**2,024**
64900	Comm-Wellspring *	128,500		128,500	$ 514	-	$ -	$ -	$ -	$ -	**514**
63530	53 Time of Day	14,201		14,201	$ 1,375	-	$ -	$ 191	$ 222	$ (12)	**1,776**
64540	54 Time of Use	37,920		37,920	$ 1,761	383	$ 2,896	$ 180	$ 580	$ -	**5,417**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,310	$ -	$ -	**4,310**
64700	70 Full Interruptable	30,435,260		30,435,260	$ 1,334,019	72,138	$ 310,121	$ 18,371	$ 316,527	$ (684)	**1,978,354**
64701	71 Partial Interruptable	1,884,104		1,884,104	$ 82,390	8,460	$ 40,569	$ 2,148	$ 19,595	$ (71)	**144,630**
63181	81 Cycled Air M*	932		932	$ (28)	-	$ -	$ -	$ -	$ -	**(28)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**131,614,329**	**149,561**	**131,464,768**	**$ 9,933,033**	**191,951**	**$ 1,308,702**	**$ 918,370**	**$ 1,823,847**	**$ (7,897)**	**13,976,055**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

May, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	per Download
63100	31 Residential	53,850,561		53,850,561	$ 5,462,370	-	$ -	$ 767,526	$ 839,860	$ (6,035)	**7,063,721**
63200	32 Resl Dem Ctrl	26,061		26,061	$ 1,689	69	$ 637	$ 166	$ 407	$ -	**2,899**
63133	33 Resid Electric Vehicles	6,511		6,511	$ 433	-	$ -	$ -	$ 102	$ -	**535**
63036	36 Irrigation	29,166		29,166	$ 1,390	346	$ 4,838	$ 240	$ 458	$ -	**6,927**
63037	37 Irrigation	117,533		117,533	$ 5,603	3,018	$ 12,224	$ 9,088	$ 1,269	$ -	**28,184**
64100	41 Sm Genl Serv	3,292,069	2,668	3,289,401	$ 326,704	-	$ -	$ 42,963	$ 51,075	$ (29)	**420,713**
62441-6244	44(1-3) Street Lights	810,120		810,120	$ 142,085.20	-	$ -	$ -	$ 13,343	$ -	**155,428**
62440	44 Security Lgts	57,346		57,346	$ 12,083	-	$ -	$ -	$ 947	$ -	**13,030**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	33,215,486	100,800	33,114,686	$ 2,048,731	113,287	$ 979,935	$ 70,654	$ 506,662	$ (903)	**3,605,079**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	10,702		10,702	$ 642	-	$ -	$ -	$ 211	$ -	**853**
63151	51 Resid Energy Stg.	603,984		603,984	$ 24,159	-	$ -	$ -	$ 1,433	$ 16	**25,609**
64151	51 Commer Energy Stg.	8,161		8,161	$ 326	-	$ -	$ -	$ -	$ 20	**346**
63152	52 Resid Interruptible	2,739,073		2,739,073	$ 131,185	-	$ -	$ -	$ 14,239	$ 28	**145,452**
64152	52 Commer Interruptible	53,070		53,070	$ 2,547	-	$ -	$ -	$ 0	$ 276	**2,823**
63900	Resid-Wellspring *	499,100		499,100	$ 1,996	-	$ -	$ -	$ -	$ -	**1,996**
64900	Comm-Wellspring *	120,400		120,400	$ 482	-	$ -	$ -	$ -	$ -	**482**
63530	53 Time of Day	12,188		12,188	$ 1,180	-	$ -	$ 184	$ 190	$ (12)	**1,542**
64540	54 Time of Use	10,128		10,128	$ 594	384	$ 2,395	$ 180	$ 155	$ -	**3,324**
64660	60 Standby Service	11,232		11,232	$ 3,792	293	$ 2,536	$ 28	$ 172	$ -	**6,528**
64700	70 Full Interruptable	32,832,730		32,832,730	$ 1,439,471	79,042	$ 339,795	$ 18,409	$ 341,460	$ (731)	**2,138,405**
64701	71 Partial Interruptable	2,034,432		2,034,432	$ 88,985	9,963	$ 48,509	$ 2,059	$ 21,158	$ (71)	**160,641**
63181	81 Cycled Air M*	165,093		165,093	$ (4,953)	-	$ -	$ -	$ -	$ -	**(4,953)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**129,720,553**	**103,468**	**129,617,085**	**$ 9,692,253**	**206,402**	**$ 1,390,869**	**$ 911,498**	**$ 1,793,141**	**$ (7,441)**	**13,780,321**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

June, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	63,905,651		63,905,651	$ 6,990,450	-	$ -	$ 769,286	$ 996,673	$ (6,164)	**8,750,245**
63200	32 Resl Dem Ctrl	19,620		19,620	$ 1,271	71	$ 809	$ 171	$ 306	$ -	**2,557**
63133	33 Resid Electric Vehicles	5,695		5,695	$ 387	-	$ -	$ -	$ 89	$ -	**476**
63036	36 Irrigation	32,686		32,686	$ 1,558	388	$ 9,242	$ 216	$ 513	$ -	**11,529**
63037	37 Irrigation	260,606		260,606	$ 12,423	7,917	$ 32,064	$ 9,094	$ 2,814	$ -	**56,396**
64100	41 Sm Genl Serv	3,391,647	2,925	3,388,722	$ 375,700	-	$ -	$ 42,767	$ 52,652	$ (43)	**471,075**
62441-6244	44(1-3) Street Lights	810,470		810,470	$ 141,986.61	-	$ -	$ -	$ 13,348	$ -	**155,335**
62440	44 Security Lgts	57,077		57,077	$ 12,022	-	$ -	$ -	$ 943	$ -	**12,965**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	35,807,021	106,560	35,700,461	$ 2,211,866	124,329	$ 1,441,590	$ 71,351	$ 546,219	$ (957)	**4,270,069**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	9,582		9,582	$ 575	-	$ -	$ -	$ 189	$ -	**764**
63151	51 Resid Energy Stg.	603,815		603,815	$ 24,153	-	$ -	$ -	$ 1,438	$ 11	**25,602**
64151	51 Commer Energy Stg.	7,560		7,560	$ 302	-	$ -	$ -	$ -	$ 18	**321**
63152	52 Resid Interruptible	2,608,809		2,608,809	$ 125,223	-	$ -	$ -	$ 13,550	$ 30	**138,802**
64152	52 Commer Interruptible	47,971		47,971	$ 2,303	-	$ -	$ -	$ -	$ 249	**2,552**
63900	Resid-Wellspring *	511,200		511,200	$ 2,045	-	$ -	$ -	$ -	$ -	**2,045**
64900	Comm-Wellspring *	125,000		125,000	$ 500	-	$ -	$ -	$ -	$ -	**500**
63530	53 Time of Day	13,224		13,224	$ 1,330	-	$ -	$ 187	$ 206	$ (12)	**1,711**
64540	54 Time of Use	57,552		57,552	$ 2,698	541	$ 5,469	$ 180	$ 881	$ -	**9,227**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,600	$ -	$ -	**5,600**
64700	70 Full Interruptable	35,101,257		35,101,257	$ 1,537,770	81,933	$ 352,314	$ 18,270	$ 365,053	$ (772)	**2,272,635**
64701	71 Partial Interruptable	1,856,872		1,856,872	$ 81,229	9,013	$ 50,453	$ 1,882	$ 19,311	$ (71)	**152,805**
63181	81 Cycled Air M*	376,488		376,488	$ (11,295)	-	$ -	$ -	$ -	$ -	**(11,295)**
63182	82&84 Cycled Air UM	-		-	$ (468,949)	-	$ -	$ -	$ -	$ -	**(468,949)**
	Total*	**144,597,115**	**109,485**	**144,487,630**	**$ 11,046,306**	**224,193**	**$ 1,891,940**	**$ 919,004**	**$ 2,014,185**	**$ (7,710)**	**15,863,724**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

July, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	80,550,314		80,550,314	$ 9,299,135	-	$ -	$ 770,171	$ 1,256,536	$ (6,400)	**11,319,442**
63200	32 Resl Dem Ctrl	16,414		16,414	$ 1,064	61	$ 788	$ 158	$ 256	$ -	**2,265**
63133	33 Resid Electric Vehicles	5,991		5,991	$ 409	-	$ -	$ -	$ 93	$ -	**503**
63036	36 Irrigation	48,359		48,359	$ 2,305	540	$ 12,856	$ 216	$ 759	$ -	**16,137**
63037	37 Irrigation	1,646,149		1,646,149	$ 78,472	20,114	$ 81,463	$ 9,130	$ 17,778	$ -	**186,843**
64100	41 Sm Genl Serv	3,595,754	2,743	3,593,011	$ 407,318	-	$ -	$ 42,868	$ 55,899	$ (104)	**505,981**
62441-6244;	44(1-3) Street Lights	810,695		810,695	$ 142,189.07	-	$ -	$ -	$ 13,352	$ -	**155,541**
62440	44 Security Lgts	57,203		57,203	$ 12,057	-	$ -	$ -	$ 945	$ -	**13,002**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	40,698,556	108,480	40,590,076	$ 2,484,340	127,395	$ 1,496,892	$ 71,152	$ 621,021	$ (962)	**4,672,443**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	13,725		13,725	$ 824	-	$ -	$ -	$ 270	$ -	**1,094**
63151	51 Resid Energy Stg.	746,300		746,300	$ 29,852	-	$ -	$ -	$ 1,791	$ -	**31,643**
64151	51 Commer Energy Stg.	7,645		7,645	$ 306	-	$ -	$ -	$ 18	$ -	**324**
63152	52 Resid Interruptible	3,345,706		3,345,706	$ 160,562	-	$ -	$ -	$ 17,414	$ -	**177,976**
64152	52 Commer Interruptible	67,463		67,463	$ 3,238	-	$ -	$ -	$ 351	$ -	**3,589**
63900	Resid-Wellspring *	524,400		524,400	$ 2,098	-	$ -	$ -	$ -	$ -	**2,098**
64900	Comm-Wellspring *	123,100		123,100	$ 492	-	$ -	$ -	$ -	$ -	**492**
63530	53 Time of Day	14,513		14,513	$ 1,468	-	$ -	$ 187	$ 226	$ (12)	**1,869**
64540	54 Time of Use	89,568		89,568	$ 3,979	725	$ 6,259	$ 180	$ 1,370	$ -	**11,788**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,600	$ -	$ -	**5,600**
64700	70 Full Interruptable	37,035,009		37,035,009	$ 1,653,192	83,616	$ 359,766	$ 18,270	$ 385,164	$ (738)	**2,415,654**
64701	71 Partial Interruptable	2,075,352		2,075,352	$ 90,768	9,622	$ 51,334	$ 2,237	$ 21,584	$ (71)	**165,852**
63181	81 Cycled Air M*	1,009,332		1,009,332	$ (30,280)	-	$ -	$ -	$ -	$ -	**(30,280)**
63182	82&84 Cycled Air UM	-		-	$ (469,254)	-	$ -	$ -	$ -	$ -	**(469,254)**
	Total*	**170,824,716**	**111,223**	**170,713,493**	**$ 13,875,291**	**242,074**	**$ 2,009,359**	**$ 920,168**	**$ 2,394,829**	**$ (8,287)**	**19,191,360**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

August, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**TOTAL REVENUE per Download**
63100	31 Residential	93,254,397		93,254,397	$ 10,764,953	-	$ -	$ 766,268	$ 1,454,689	$ (6,413)	**12,979,496**
63200	32 Resl Dem Ctrl	17,928		17,928	$ 1,162	67	$ 858	$ 165	$ 280	$ -	**2,464**
63133	33 Resid Electric Vehicles	6,400		6,400	$ 445	-	$ -	$ -	$ 100	$ -	**545**
63036	36 Irrigation	63,041		63,041	$ 3,005	547	$ 13,021	$ 216	$ 990	$ -	**17,232**
63037	37 Irrigation	2,849,222		2,849,222	$ 135,822	23,030	$ 93,271	$ 9,143	$ 30,772	$ -	**269,008**
64100	41 Sm Genl Serv	3,684,717	2,770	3,681,947	$ 417,257	-	$ -	$ 42,749	$ 57,285	$ (112)	**517,179**
62441-6244	44(1-3) Street Lights	815,650		815,650	$ 143,039.13	-	$ -	$ -	$ 13,434	$ -	**156,473**
62440	44 Security Lgts	57,443		57,443	$ 12,110	-	$ -	$ -	$ 949	$ -	**13,059**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	41,084,265	109,440	40,974,825	$ 2,523,305	132,292	$ 1,554,429	$ 71,409	$ 626,897	$ (1,032)	**4,775,009**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	15,233		15,233	$ 914	-	$ -	$ -	$ 300	$ -	**1,214**
63151	51 Resid Energy Stg.	887,874		887,874	$ 35,515	-	$ -	$ -	$ 2,131	$ -	**37,646**
64151	51 Commer Energy Stg.	8,972		8,972	$ 359	-	$ -	$ -	$ 22	$ -	**380**
63152	52 Resid Interruptible	4,161,841		4,161,841	$ 199,768	-	$ -	$ -	$ 21,668	$ -	**221,436**
64152	52 Commer Interruptible	76,922		76,922	$ 3,692	-	$ -	$ -	$ 400	$ -	**4,092**
63900	Resid-Wellspring *	536,900		536,900	$ 2,148	-	$ -	$ -	$ -	$ -	**2,148**
64900	Comm-Wellspring *	125,900		125,900	$ 504	-	$ -	$ -	$ -	$ -	**504**
63530	53 Time of Day	15,841		15,841	$ 1,625	-	$ -	$ 187	$ 247	$ (12)	**2,047**
64540	54 Time of Use	129,504		129,504	$ 5,690	1,032	$ 9,148	$ 180	$ 1,981	$ -	**17,000**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,600	$ -	$ -	**5,600**
64700	70 Full Interruptable	36,592,895		36,592,895	$ 1,604,448	82,733	$ 355,750	$ 18,270	$ 380,566	$ (763)	**2,358,272**
64701	71 Partial Interruptable	2,271,640		2,271,640	$ 99,388	9,544	$ 53,332	$ 2,059	$ 23,625	$ (72)	**178,333**
63181	81 Cycled Air M*	1,454,347		1,454,347	$ (43,630)	-	$ -	$ -	$ -	$ -	**(43,630)**
63182	82&84 Cycled Air UM	-		-	$ (469,535)	-	$ -	$ -	$ -	$ -	**(469,535)**
	Total*	**185,993,785**	**112,210**	**185,881,575**	**$ 15,442,741**	**249,244**	**$ 2,079,810**	**$ 916,246**	**$ 2,616,334**	**$ (8,403)**	**21,046,729**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

September, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	84,262,420		84,262,420	$ 9,111,077	-	$ -	$ 770,849	$ 1,314,401	$ (6,456)	**11,189,871**
63200	32 Resl Dem Ctrl	17,958		17,958	$ 1,164	64	$ 666	$ 165	$ 280	$ -	**2,275**
63133	33 Resid Electric Vehicles	6,255		6,255	$ 435	-	$ -	$ -	$ 98	$ -	**533**
63036	36 Irrigation	45,917		45,917	$ 2,189	490	$ 6,856	$ 216	$ 721	$ -	**9,982**
63037	37 Irrigation	792,217		792,217	$ 37,765	17,282	$ 69,991	$ 9,163	$ 8,556	$ -	**125,475**
64100	41 Sm Genl Serv	3,660,045	3,051	3,656,994	$ 372,000	-	$ -	$ 42,779	$ 56,899	$ (87)	**471,592**
62441-6244	44(1-3) Street Lights	818,800		818,800	$ 143,553.22	-	$ -	$ -	$ 13,486	$ -	**157,039**
62440	44 Security Lgts	56,604		56,604	$ 11,996	-	$ -	$ -	$ 935	$ -	**12,931**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	41,758,629	103,680	41,654,949	$ 2,555,839	131,746	$ 1,164,334	$ 71,706	$ 637,284	$ (975)	**4,428,188**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	13,251		13,251	$ 795	-	$ -	$ -	$ 261	$ -	**1,056**
63151	51 Resid Energy Stg.	738,365		738,365	$ 29,535	-	$ -	$ -	$ 1,772	$ -	**31,307**
64151	51 Commer Energy Stg.	7,714		7,714	$ 309	-	$ -	$ -	$ 19	$ -	**327**
63152	52 Resid Interruptible	3,376,375		3,376,375	$ 162,066	-	$ -	$ -	$ 17,588	$ -	**179,654**
64152	52 Commer Interruptible	61,992		61,992	$ 2,976	-	$ -	$ -	$ 322	$ -	**3,298**
63900	Resid-Wellspring *	524,700		524,700	$ 2,099	-	$ -	$ -	$ -	$ -	**2,099**
64900	Comm-Wellspring *	123,100		123,100	$ 492	-	$ -	$ -	$ -	$ -	**492**
63530	53 Time of Day	15,345		15,345	$ 1,511	-	$ -	$ 187	$ 239	$ (12)	**1,926**
64540	54 Time of Use	200,544		200,544	$ 8,812	860	$ 4,313	$ 180	$ 3,068	$ -	**16,373**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,310	$ -	$ -	**4,310**
64700	70 Full Interruptable	34,894,881		34,894,881	$ 1,530,199	84,125	$ 361,737	$ 18,279	$ 362,907	$ (758)	**2,272,364**
64701	71 Partial Interruptable	2,382,232		2,382,232	$ 104,267	10,080	$ 47,725	$ 2,059	$ 24,775	$ (71)	**178,755**
63181	81 Cycled Air M*	1,033,785		1,033,785	$ (31,014)	-	$ -	$ -	$ -	$ -	**(31,014)**
63182	82&84 Cycled Air UM	-		-	$ (3)	-	$ -	$ -	$ -	$ -	**(3)**
	Total*	**173,109,544**	**106,731**	**173,002,813**	**$ 14,048,820**	**244,646**	**$ 1,655,623**	**$ 919,894**	**$ 2,443,612**	**$ (8,359)**	**19,059,589**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

October, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW						**TOTAL**
			DEA	kWh	Revenue			Fixed			Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges		RTA	Adjustments	**per Download**
63100	31 Residential	68,121,157		68,121,157	$ 6,909,794	-	$ -	$ 769,152		$ 1,062,380	$ (6,214)	**8,735,111**
63200	32 Resl Dem Ctrl	15,875		15,875	$ 1,029	50	$ 466	$ 165		$ 248	$ -	**1,907**
63133	33 Resid Electric Vehicles	7,069		7,069	$ 523	-	$ -	$ -		$ 110	$ -	**633**
63036	36 Irrigation	34,093		34,093	$ 1,625	331	$ 4,638	$ 216		$ 535	$ -	**7,014**
63037	37 Irrigation	78,027		78,027	$ 3,720	2,341	$ 9,481	$ 9,155		$ 843	$ -	**23,198**
64100	41 Sm Genl Serv	3,259,934	3,055	3,256,879	$ 323,522	-	$ -	$ 43,038		$ 50,657	$ (93)	**417,125**
62441-6244:	44(1-3) Street Lights	820,117		820,117	$ 143,474.74	-	$ -	$ -		$ 13,508	$ -	**156,982**
62440	44 Security Lgts	56,084		56,084	$ 11,921	-	$ -	$ -		$ 927	$ -	**12,848**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -		$ -	$ -	**432**
64600	46 General Service	35,644,237	98,400	35,545,837	$ 2,200,340	119,908	$ 1,037,208	$ 71,899		$ 543,815	$ (855)	**3,852,408**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -		$ -	$ -	**325**
64690	49 Geotherm Heat Pump	13,543		13,543	$ 813	-	$ -	$ -		$ 267	$ -	**1,079**
63151	51 Resid Energy Stg.	544,684		544,684	$ 21,787	-	$ -	$ -		$ 1,307	$ -	**23,095**
64151	51 Commer Energy Stg.	5,737		5,737	$ 229	-	$ -	$ -		$ 14	$ -	**243**
63152	52 Resid Interruptible	2,515,635		2,515,635	$ 120,750	-	$ -	$ -		$ 13,185	$ -	**133,935**
64152	52 Commer Interruptible	44,920		44,920	$ 2,156	-	$ -	$ -		$ 234	$ -	**2,390**
63900	Resid-Wellspring *	504,600		504,600	$ 2,018	-	$ -	$ -		$ -	$ -	**2,018**
64900	Comm-Wellspring *	118,700		118,700	$ 475	-	$ -	$ -		$ -	$ -	**475**
63530	53 Time of Day	12,831		12,831	$ 1,258	-	$ -	$ 187		$ 200	$ (12)	**1,634**
64540	54 Time of Use	155,904		155,904	$ 6,912	583	$ 3,431	$ 180		$ 2,385	$ -	**12,909**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,310		$ -	$ -	**4,310**
64700	70 Full Interruptable	31,224,446		31,224,446	$ 1,369,111	73,313	$ 315,247	$ 18,279		$ 324,734	$ (721)	**2,026,650**
64701	71 Partial Interruptable	2,355,400		2,355,400	$ 103,133	9,375	$ 44,846	$ 2,059		$ 24,496	$ (72)	**174,463**
63181	81 Cycled Air M*	473,362		473,362	$ (14,201)	-	$ -	$ -		$ -	$ -	**(14,201)**
63182	82&84 Cycled Air UM	-		-	$ (36)	-	$ -	$ -		$ -	$ -	**(36)**
	Total*	**144,909,693**	**101,455**	**144,808,238**	**$ 11,211,113**	**205,901**	**$ 1,415,317**	**$ 918,641**		**$ 2,039,844**	**$ (7,967)**	**15,576,947**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

November, 2015

(Accounting Month information downloaded from Orcom)

		kWh				KW						TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	56,792,060		56,792,060	$ 5,759,868	-	$ -	$ 767,336	$ 885,635	$ (6,181)	**7,406,659**
63200	32 Resl Dem Ctrl	22,691		22,691	$ 1,470	59	$ 550	$ 165	$ 354	$ -	**2,539**
63133	33 Resid Electric Vehicles	6,345		6,345	$ 450	-	$ -	$ -	$ 99	$ -	**549**
63036	36 Irrigation	8,207		8,207	$ 391	237	$ 3,317	$ 216	$ 129	$ -	**4,054**
63037	37 Irrigation	16,228		16,228	$ 774	790	$ 3,200	$ 9,192	$ 175	$ -	**13,340**
64100	41 Sm Genl Serv	3,218,419	3,244	3,215,175	$ 319,887	-	$ -	$ 42,755	$ 50,009	$ (95)	**412,556**
62441-6244:	44(1-3) Street Lights	821,670		821,670	$ 143,742.10	-	$ -	$ -	$ 13,533	$ -	**157,275**
62440	44 Security Lgts	55,538		55,538	$ 11,810	-	$ -	$ -	$ 918	$ -	**12,727**
64500	45 Emergency Unmet.	-		-	$ 432	-	$ -	$ -	$ -	$ -	**432**
64600	46 General Service	32,731,185	136,704	32,594,481	$ 2,016,012	106,433	$ 917,959	$ 71,810	$ 498,674	$ (859)	**3,503,596**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	12,386		12,386	$ 743	-	$ -	$ -	$ 244	$ -	**987**
63151	51 Resid Energy Stg.	505,194		505,194	$ 20,208	-	$ -	$ -	$ 1,212	$ -	**21,420**
64151	51 Commer Energy Stg.	4,844		4,844	$ 194	-	$ -	$ -	$ 12	$ -	**205**
63152	52 Resid Interruptible	2,489,952		2,489,952	$ 119,518	-	$ -	$ -	$ 13,056	$ -	**132,573**
64152	52 Commer Interruptible	54,442		54,442	$ 2,613	-	$ -	$ -	$ 283	$ -	**2,896**
63900	Resid-Wellspring *	491,900		491,900	$ 1,968	-	$ -	$ -	$ -	$ -	**1,968**
64900	Comm-Wellspring *	130,700		130,700	$ 523	-	$ -	$ -	$ -	$ -	**523**
63530	53 Time of Day	13,694		13,694	$ 1,321	-	$ -	$ 189	$ 214	$ (12)	**1,711**
64540	54 Time of Use	110,160		110,160	$ 4,848	632	$ 3,510	$ 180	$ 1,685	$ -	**10,223**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,310	$ -	$ -	**4,310**
64700	70 Full Interruptable	29,549,464		29,549,464	$ 1,294,577	70,443	$ 302,904	$ 18,319	$ 307,314	$ (679)	**1,922,436**
64701	71 Partial Interruptable	1,636,216		1,636,216	$ 71,483	9,231	$ 44,637	$ 2,059	$ 17,017	$ (72)	**135,123**
63181	81 Cycled Air M*	29,909		29,909	$ (897)	-	$ -	$ -	$ -	$ -	**(897)**
63182	82&84 Cycled Air UM	-		-	$ (36)	-	$ -	$ -	$ -	$ -	**(36)**
	Total*	**128,048,695**	**139,948**	**127,908,747**	**$ 9,772,222**	**187,825**	**$ 1,276,077**	**$ 916,531**	**$ 1,790,562**	**$ (7,897)**	**13,747,495**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

December, 2015

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	63,127,163		63,127,163	$ 7,372,813	-	$ -	$ 868,561	$ 176,629	$ (6,322)	**8,411,681**
63200	32 Resl Dem Ctrl	36,156		36,156	$ 2,748	75	$ 829	$ 180	$ 101	$ -	**3,858**
63133	33 Resid Electric Vehicles	7,274		7,274	$ 602	-	$ -	$ -	$ 20	$ -	**623**
63036	36 Irrigation	1,875		1,875	$ 94	70	$ 1,461	$ 270	$ 6	$ -	**1,831**
63037	37 Irrigation	7,024		7,024	$ 351	5	$ 74	$ 11,422	$ 22	$ -	**11,869**
64100	41 Sm Genl Serv	3,555,012	7,562	3,547,450	$ 399,853	-	$ -	$ 59,958	$ 9,924	$ (98)	**469,637**
62441-6244	44(1-3) Street Lights	822,690		822,690	$ 157,124.37	-	$ -	$ -	$ 2,468	$ -	**159,592**
62440	44 Security Lgts	55,965		55,965	$ 12,809	-	$ -	$ -	$ 168	$ -	**12,977**
64500	45 Emergency Unmet.	-		-	$ 540	-	$ -	$ -	$ -	$ -	**540**
64600	46 General Service	34,274,866	232,320	34,042,546	$ 2,464,332	105,168	$ 963,281	$ 87,667	$ 95,283	$ (804)	**3,609,759**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	15,623		15,623	$ 1,449	-	$ -	$ -	$ 84	$ -	**1,533**
63151	51 Resid Energy Stg.	728,487		728,487	$ 31,782	-	$ -	$ -	$ 219	$ -	**32,001**
64151	51 Commer Energy Stg.	8,027		8,027	$ 353	-	$ -	$ -	$ 2	$ -	**356**
63152	52 Resid Interruptible	3,487,864		3,487,864	$ 191,838	-	$ -	$ -	$ 2,800	$ -	**194,638**
64152	52 Commer Interruptible	119,430		119,430	$ 6,573	-	$ -	$ -	$ 93	$ -	**6,666**
63900	Resid-Wellspring *	503,200		503,200	$ 2,013	-	$ -	$ -	$ -	$ -	**2,013**
64900	Comm-Wellspring *	463,600		463,600	$ 1,854	-	$ -	$ -	$ -	$ -	**1,854**
63530	53 Time of Day	17,485		17,485	$ 1,948	-	$ -	$ 216	$ 49	$ (12)	**2,201**
64540	54 Time of Use	100,128		100,128	$ 4,996	634	$ 4,423	$ 216	$ 280	$ -	**9,916**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,320	$ -	$ -	**5,320**
64700	70 Full Interruptable	30,377,061		30,377,061	$ 1,513,111	64,616	$ 306,925	$ 24,997	$ 88,094	$ (614)	**1,932,513**
64701	71 Partial Interruptable	1,635,336		1,635,336	$ 81,186	6,064	$ 41,104	$ 2,661	$ 4,742	$ (71)	**129,622**
63181	81 Cycled Air M*	57		57	$ (2)	-	$ -	$ -	$ -	$ -	**(2)**
63182	82&84 Cycled Air UM	-		-	$ (12)	-	$ -	$ -	$ -	$ -	**(12)**
	Total*	**138,377,466**	**239,882**	**138,137,584**	**$ 12,248,681**	**176,632**	**$ 1,318,098**	**$ 1,061,467**	**$ 380,984**	**$ (7,922)**	**15,001,309**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association
SALES BY RATE (Billed)
Full Year 2016
(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	ADJUSTED
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	REVENUE
63100	31 Residential	846,714,198	-	846,714,198	102,673,011	-	-	10,474,418	2,540,021	(70,908)	115,616,541
63200	32 Resl Dem Ctrl	362,153	-	362,153	27,524	910	10,742	2,146	1,087	-	41,498
63133	33 Resid Electric Vehicles	95,957	-	95,957	7,972	-	-	-	288	-	8,260
63036	36 Irrigation	294,350	-	294,350	14,688	3,515	72,777	3,060	942	-	91,467
63039	39 Irrigation	6,707,773	-	6,707,773	334,721	78,629	357,762	137,976	(10,065)	-	820,394
64100	41 Sm Genl Serv	42,951,724	47,400	42,904,324	4,988,152	-	-	723,373	124,117	(1,221)	5,834,422
62441-62443	44(1-3) Street Lights	10,668,929	-	10,668,929	1,881,895	-	-	-	30,942	-	1,912,837
62440	44 Security Lgts	497,650	-	497,650	112,296	-	-	-	1,456	-	113,753
62444	44 Security Lgts - LED	46,740	-	46,740	22,653	-	-	-	145	-	22,798
62446	44 Street Lgts - LED	22,325	-	22,325	7,186	-	-	-	65	-	7,251
64500	45 Emergency Unmet.	-	-	-	6,730	-	-	-	-	-	6,730
64600	46 General Service	450,572,701	2,005,152	448,567,549	32,563,063	1,411,554	14,157,578	1,058,971	1,345,801	(12,136)	49,113,277
63047	47 Municipal	-	-	-	3,900	-	-	-	-	-	3,900
64690	49 Geotherm Heat Pump	176,572	-	176,572	16,598	-	-	-	247	-	16,845
63151	51 Resid Energy Stg.	9,294,102	-	9,294,102	408,179	-	-	-	13,013	-	421,192
64151	51 Commer Energy Stg.	106,186	-	106,186	4,672	-	-	-	149	-	4,821
63152	52 Resid Interruptible	43,035,327	-	43,035,327	2,365,419	-	-	-	25,895	-	2,391,314
64152	52 Commer Interruptible	1,054,810	-	1,054,810	58,015	-	-	-	633	-	58,649
63900	Resid-Wellspring *	6,078,200	-	6,078,200	24,313	-	-	-	-	-	24,313
63901	Resid-Wellspring Solar *	47,600	-	47,600	952	-	-	-	-	-	952
64900	Comm-Wellspring *	2,599,800	-	2,599,800	10,399	-	-	-	-	-	10,399
64901	Comm-Wellspring Solar*	27,500	-	27,500	550	-	-	-	-	-	550
63530	53 Time of Day	208,318	-	208,318	23,679	-	-	2,594	625	(144)	26,754
64540	54 Time of Use	935,040	-	935,040	47,092	7,651	58,931	2,592	2,805	-	111,421
64660	60 Standby Service	10,944	-	10,944	4,130	318	2,911	60,801	33	199	68,075
64700	70 Full Interruptable	389,394,755	-	389,394,755	19,408,971	894,529	4,249,024	304,524	(700,911)	(7,813)	23,253,795
64701	71 Partial Interruptable	22,681,544	-	22,681,544	1,126,462	101,646	591,548	33,064	(40,827)	(854)	1,709,394
63181	81 Cycled Air M*	4,952,327	-	4,952,327	(158,475)	-	-	-	-	-	(158,475)
63182	82&84 Cycled Air UM	-	-	-	(1,552,548)	-	-	-	-	-	(1,552,548)
	Total	**1,825,832,098**	**2,052,552**	**1,823,779,546**	**$ 164,432,201**	**2,498,752**	**$ 19,501,275**	**$ 12,803,518**	**$ 3,336,462**	**$ (92,877)**	**199,980,579**

*Note: kWh Sales total does not foot since rate 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

January, 2016

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	TOTAL REVENUE per Download
63100	31 Residential	73,222,904		73,222,904	$ 8,551,767	-	$ -	$ 868,665	$ 219,627	$ (6,415)	**9,633,643**
63200	32 Resl Dem Ctrl	49,466		49,466	$ 3,759	102	$ 1,135	$ 180	$ 148	$ -	**5,223**
63133	33 Resid Electric Vehicles	8,385		8,385	$ 723	-	$ -	$ -	$ 25	$ -	**748**
63036	36 Irrigation	326		326	$ 16	6	$ 132	$ 270	$ 1	$ -	**420**
63037	37 Irrigation	8,509		8,509	$ 425	(54)	$ (243)	$ 11,492	$ (16)	$ -	**11,657**
64100	41 Sm Genl Serv	4,121,114	9,282	4,111,832	$ 463,719	-	$ -	$ 60,073	$ 11,913	$ (92)	**535,613**
62441-6244:	44(1-3) Street Lights	921,014		921,014	$ 157,175	-	$ -	$ -	$ 2,671	$ -	**159,845**
62440	44 Security Lgts	49,657		49,657	$ 10,739	-	$ -	$ -	$ 143	$ -	**10,882**
62444	44 Security Lgts - LED	1,022		1,022	$ 387	-	$ -	$ -	$ 3	$ -	**390**
62446	44 Street Lgts - LED	57		57	$ 18	-	$ -	$ -	$ 0	$ -	**19**
64500	45 Emergency Unmet.	-		-	$ 540	-	$ -	$ -	$ -	$ -	**540**
64600	46 General Service	38,471,067	289,920	38,181,147	$ 2,744,112	108,936	$ 997,852	$ 87,728	$ 114,605	$ (847)	**3,943,451**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	20,432		20,432	$ 1,921	-	$ -	$ -	$ 29	$ -	**1,949**
63151	51 Resid Energy Stg.	936,110		936,110	$ 41,189	-	$ -	$ -	$ 1,311	$ -	**42,500**
64151	51 Commer Energy Stg.	13,008		13,008	$ 572	-	$ -	$ -	$ 18	$ -	**591**
63152	52 Resid Interruptible	4,506,291		4,506,291	$ 247,869	-	$ -	$ -	$ 2,701	$ -	**250,570**
64152	52 Commer Interruptible	147,884		147,884	$ 8,134	-	$ -	$ -	$ 89	$ -	**8,223**
63900	Resid-Wellspring *	518,600		518,600	$ 2,074	-	$ -	$ -	$ -	$ -	**2,074**
63901	Resid-Wellspring Solar*	1,400		1,400	$ 28	-	$ -	$ -	$ -	$ -	**28**
64900	Comm-Wellspring *	536,300		536,300	$ 2,145	-	$ -	$ -	$ -	$ -	**2,145**
64901	Comm-Wellspring Solar*	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
63530	53 Time of Day	20,462		20,462	$ 2,279	-	$ -	$ 216	$ 61	$ (12)	**2,544**
64540	54 Time of Use	123,840		123,840	$ 6,180	633	$ 6,572	$ 216	$ 372	$ -	**13,339**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,520	$ -	$ -	**5,520**
64700	70 Full Interruptable	30,635,124		30,635,124	$ 1,525,882	64,648	$ 307,078	$ 24,997	$ (55,143)	$ (636)	**1,802,179**
64701	71 Partial Interruptable	1,698,200		1,698,200	$ 84,357	5,681	$ 35,197	$ 2,661	$ (3,057)	$ (72)	**119,087**
63181	81 Cycled Air M*	95		95	$ (3)	-	$ -	$ -	$ -	$ -	**(3)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**154,954,872**	**299,202**	**154,655,670**	**$ 13,856,333**	**179,953**	**$ 1,347,724**	**$ 1,062,018**	**$ 295,501**	**$ (8,073)**	**16,553,501**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

February, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	72,241,650		72,241,650	$ 8,436,787	-	$ -	$ 869,513	$ 216,692	$ (6,375)	**9,516,617**
63200	32 Resl Dem Ctrl	62,787		62,787	$ 4,772	111	$ 1,228	$ 180	$ 188	$ -	**6,368**
63133	33 Resid Electric Vehicles	9,371		9,371	$ 754	-	$ -	$ -	$ 28	$ -	**782**
63036	36 Irrigation	830		830	$ 41	91	$ 1,915	$ 270	$ 3	$ -	**2,230**
63037	37 Irrigation	22,097		22,097	$ 1,103	29	$ 133	$ 11,460	$ (33)	$ -	**12,663**
64100	41 Sm Genl Serv	4,270,604	8,576	4,262,028	$ 480,615	-	$ -	$ 60,119	$ 12,347	$ (110)	**552,971**
62441-6244;	44(1-3) Street Lights	888,426		888,426	$ 157,145.76	-	$ -	$ -	$ 2,577	$ -	**159,722**
62440	44 Security Lgts	42,187		42,187	$ 9,502	-	$ -	$ -	$ 123	$ -	**9,626**
62444	44 Security Lgts - LED	3,260		3,260	$ 1,569	-	$ -	$ -	$ 10	$ -	**1,579**
62446	44 Street Lgts - LED	188		188	$ 61	-	$ -	$ -	$ 1	$ -	**62**
64500	45 Emergency Unmet.	-		-	$ 540	-	$ -	$ -	$ -	$ -	**540**
64600	46 General Service	37,792,368	257,760	37,534,608	$ 2,694,891	103,580	$ 948,789	$ 88,077	$ 112,583	$ (861)	**3,843,479**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	25,451		25,451	$ 2,392	-	$ -	$ -	$ 36	$ -	**2,428**
63151	51 Resid Energy Stg.	1,044,108		1,044,108	$ 45,941	-	$ -	$ -	$ 1,462	$ -	**47,403**
64151	51 Commer Energy Stg.	16,599		16,599	$ 730	-	$ -	$ -	$ 23	$ -	**754**
63152	52 Resid Interruptible	5,133,494		5,133,494	$ 282,201	-	$ -	$ -	$ 3,092	$ -	**285,293**
64152	52 Commer Interruptible	176,177		176,177	$ 9,690	-	$ -	$ -	$ 106	$ -	**9,796**
63900	Resid-Wellspring *	518,900		518,900	$ 2,076	-	$ -	$ -	$ -	$ -	**2,076**
63901	Resid-Wellspring Solar*	3,300		3,300	$ 66	-	$ -	$ -	$ -	$ -	**66**
64900	Comm-Wellspring *	270,400		270,400	$ 1,082	-	$ -	$ -	$ -	$ -	**1,082**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	21,668		21,668	$ 2,429	-	$ -	$ 216	$ 65	$ (12)	**2,698**
64540	54 Time of Use	111,984		111,984	$ 5,588	892	$ 9,003	$ 216	$ 336	$ -	**15,143**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,520	$ -	$ -	**5,520**
64700	70 Full Interruptable	28,765,062		28,765,062	$ 1,432,606	64,161	$ 304,765	$ 24,997	$ (51,777)	$ (625)	**1,709,966**
64701	71 Partial Interruptable	1,524,608		1,524,608	$ 75,743	5,767	$ 36,251	$ 2,661	$ (2,744)	$ (71)	**111,839**
63181	81 Cycled Air M*	532		532	$ (17)	-	$ -	$ -	$ -	$ -	**(17)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**152,152,919**	**266,336**	**151,886,583**	**$ 13,648,681**	**174,631**	**$ 1,302,084**	**$ 1,063,229**	**$ 295,118**	**$ (8,053)**	**16,301,058**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

March, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	62,588,249		62,588,249	$ 7,309,720	-	$ -	$ 872,896	$ 187,762	$ (5,794)	**8,364,583**
63200	32 Resl Dem Ctrl	46,361		46,361	$ 3,523	120	$ 1,330	$ 180	$ 139	$ -	**5,172**
63133	33 Resid Electric Vehicles	8,464		8,464	$ 702	-	$ -	$ -	$ 25	$ -	**728**
63036	36 Irrigation	757		757	$ 38	22	$ 346	$ 270	$ 2	$ -	**656**
63037	37 Irrigation	14,131		14,131	$ 705	225	$ 1,022	$ 11,440	$ (21)	$ -	**13,146**
64100	41 Sm Genl Serv	3,763,295	4,704	3,758,591	$ 423,367	-	$ -	$ 60,301	$ 10,876	$ (102)	**494,442**
62441-6244	44(1-3) Street Lights	888,259		888,259	$ 157,181.24	-	$ -	$ -	$ 2,576	$ -	**159,757**
62440	44 Security Lgts	41,192		41,192	$ 9,341	-	$ -	$ -	$ 121	$ -	**9,462**
62444	44 Security Lgts - LED	4,177		4,177	$ 2,036	-	$ -	$ -	$ 13	$ -	**2,049**
62446	44 Street Lgts - LED	188		188	$ 61	-	$ -	$ -	$ 1	$ -	**62**
64500	45 Emergency Unmet.	-		-	$ 540	-	$ -	$ -	$ -	$ -	**540**
64600	46 General Service	34,858,880	191,904	34,666,976	$ 2,511,402	104,747	$ 959,480	$ 87,706	$ 103,998	$ (803)	**3,661,783**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	18,255		18,255	$ 1,716	-	$ -	$ -	$ 26	$ -	**1,742**
63151	51 Resid Energy Stg.	879,943		879,943	$ 38,718	-	$ -	$ -	$ 1,232	$ -	**39,950**
64151	51 Commer Energy Stg.	13,391		13,391	$ 589	-	$ -	$ -	$ 19	$ -	**608**
63152	52 Resid Interruptible	4,191,248		4,191,248	$ 230,528	-	$ -	$ -	$ 2,521	$ -	**233,049**
64152	52 Commer Interruptible	116,498		116,498	$ 6,407	-	$ -	$ -	$ 70	$ -	**6,477**
63900	Resid-Wellspring *	501,100		501,100	$ 2,004	-	$ -	$ -	$ -	$ -	**2,004**
63901	Resid-Wellspring Solar*	3,500		3,500	$ 70	-	$ -	$ -	$ -	$ -	**70**
64900	Comm-Wellspring *	211,900		211,900	$ 848	-	$ -	$ -	$ -	$ -	**848**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	16,449		16,449	$ 1,837	-	$ -	$ 216	$ 49	$ (12)	**2,090**
64540	54 Time of Use	111,744		111,744	$ 5,576	734	$ 5,647	$ 216	$ 335	$ -	**11,774**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,810	$ -	$ -	**4,810**
64700	70 Full Interruptable	30,457,608		30,457,608	$ 1,517,377	67,717	$ 321,657	$ 24,997	$ (54,824)	$ (656)	**1,808,551**
64701	71 Partial Interruptable	1,758,424		1,758,424	$ 87,362	6,935	$ 38,269	$ 2,669	$ (3,165)	$ (71)	**125,063**
63181	81 Cycled Air M*	195		195	$ (6)	-	$ -	$ -	$ -	$ -	**(6)**
63182	82&84 Cycled Air UM	-		-	$ (36)	-	$ -	$ -	$ -	$ -	**(36)**
	Total*	**139,777,513**	**196,608**	**139,580,905**	**$ 12,311,982**	**180,500**	**$ 1,327,749**	**$ 1,065,702**	**$ 251,755**	**$ (7,439)**	**14,949,748**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

April, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW						TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	55,824,485		55,824,485	$ 6,519,598	-	$ -	$ 873,200	$ 167,480	$ (5,842)	**7,554,437**
63200	32 Resl Dem Ctrl	32,845		32,845	$ 2,496	89	$ 984	$ 180	$ 99	$ -	**3,759**
63133	33 Resid Electric Vehicles	6,955		6,955	$ 561	-	$ -	$ -	$ 21	$ -	**582**
63036	36 Irrigation	10,812		10,812	$ 540	269	$ 4,164	$ 270	$ 35	$ -	**5,008**
63037	37 Irrigation	59,824		59,824	$ 2,986	1,887	$ 8,586	$ 11,449	$ (90)	$ -	**22,931**
64100	41 Sm Genl Serv	3,329,306	4,005	3,325,301	$ 374,401	-	$ -	$ 60,256	$ 9,617	$ (100)	**444,174**
62441-6244	44(1-3) Street Lights	888,008		888,008	$ 157,131.50	-	$ -	$ -	$ 2,575	$ -	**159,707**
62440	44 Security Lgts	41,078		41,078	$ 9,314	-	$ -	$ -	$ 121	$ -	**9,435**
62444	44 Security Lgts - LED	4,207		4,207	$ 2,051	-	$ -	$ -	$ 13	$ -	**2,064**
62446	44 Street Lgts - LED	219		219	$ 70	-	$ -	$ -	$ 1	$ -	**71**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	32,296,618	150,720	32,145,898	$ 2,359,600	110,858	$ 1,015,455	$ 87,836	$ 96,441	$ (874)	**3,558,457**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	13,065		13,065	$ 1,228	-	$ -	$ -	$ 18	$ -	**1,246**
63151	51 Resid Energy Stg.	753,543		753,543	$ 33,156	-	$ -	$ -	$ 1,055	$ -	**34,211**
64151	51 Commer Energy Stg.	9,401		9,401	$ 414	-	$ -	$ -	$ 13	$ -	**427**
63152	52 Resid Interruptible	3,406,281		3,406,281	$ 185,853	-	$ -	$ -	$ 2,048	$ -	**187,901**
64152	52 Commer Interruptible	85,606		85,606	$ 4,708	-	$ -	$ -	$ 51	$ -	**4,760**
63900	Resid-Wellspring *	492,700		492,700	$ 1,971	-	$ -	$ -	$ -	$ -	**1,971**
63901	Resid-Wellspring Solar*	4,000		4,000	$ 80	-	$ -	$ -	$ -	$ -	**80**
64900	Comm-Wellspring *	119,400		119,400	$ 478	-	$ -	$ -	$ -	$ -	**478**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	14,843		14,843	$ 1,650	-	$ -	$ 221	$ 45	$ (12)	**1,903**
64540	54 Time of Use	81,264		81,264	$ 4,141	551	$ 4,027	$ 216	$ 244	$ -	**8,628**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,810	$ -	$ -	**4,810**
64700	70 Full Interruptable	29,787,009		29,787,009	$ 1,483,667	71,732	$ 340,728	$ 24,997	$ (53,617)	$ (667)	**1,795,109**
64701	71 Partial Interruptable	1,880,872		1,880,872	$ 93,485	8,375	$ 45,347	$ 2,779	$ (3,386)	$ (71)	**138,154**
63181	81 Cycled Air M*	359		359	$ (11)	-	$ -	$ -	$ -	$ -	**(11)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**128,526,241**	**154,725**	**128,371,516**	**$ 11,240,494**	**193,760**	**$ 1,419,290**	**$ 1,066,215**	**$ 222,784**	**$ (7,567)**	**13,941,216**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

May, 2016

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**TOTAL REVENUE per Download**
63100	31 Residential	55,735,369		55,735,369	$ 6,509,686	-	$ -	$ 874,934	$ 167,222	$ (5,825)	**7,546,017**
63200	32 Resl Dem Ctrl	27,252		27,252	$ 2,071	56	$ 618	$ 180	$ 82	$ -	**2,951**
63133	33 Resid Electric Vehicles	6,824		6,824	$ 565	-	$ -	$ -	$ 21	$ -	**585**
63036	36 Irrigation	41,926		41,926	$ 2,092	447	$ 6,932	$ 270	$ 134	$ -	**9,429**
63037	37 Irrigation	186,740		186,740	$ 9,319	6,289	$ 28,617	$ 11,450	$ (280)	$ -	**49,106**
64100	41 Sm Genl Serv	3,092,653	2,548	3,090,105	$ 347,718	-	$ -	$ 60,195	$ 8,932	$ (94)	**416,751**
62441-6244	44(1-3) Street Lights	887,730		887,730	$ 157,084.54	-	$ -	$ -	$ 2,575	$ -	**159,659**
62440	44 Security Lgts	40,909		40,909	$ 9,281	-	$ -	$ -	$ 120	$ -	**9,401**
62444	44 Security Lgts - LED	4,189		4,189	$ 2,043	-	$ -	$ -	$ 13	$ -	**2,056**
62446	44 Street Lgts - LED	258		258	$ 82	-	$ -	$ -	$ 1	$ -	**83**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	32,684,197	101,760	32,582,437	$ 2,395,563	115,760	$ 1,060,358	$ 87,789	$ 97,755	$ (859)	**3,640,606**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	11,213		11,213	$ 1,054	-	$ -	$ -	$ 16	$ -	**1,070**
63151	51 Resid Energy Stg.	634,524		634,524	$ 27,856	-	$ -	$ -	$ 888	$ -	**28,744**
64151	51 Commer Energy Stg.	5,945		5,945	$ 262	-	$ -	$ -	$ 8	$ -	**270**
63152	52 Resid Interruptible	2,713,526		2,713,526	$ 149,254	-	$ -	$ -	$ 1,631	$ -	**150,884**
64152	52 Commer Interruptible	49,841		49,841	$ 2,741	-	$ -	$ -	$ 30	$ -	**2,771**
63900	Resid-Wellspring *	489,900		489,900	$ 1,960	-	$ -	$ -	$ -	$ -	**1,960**
63901	Resid-Wellspring Solar*	3,900		3,900	$ 78	-	$ -	$ -	$ -	$ -	**78**
64900	Comm-Wellspring *	116,700		116,700	$ 467	-	$ -	$ -	$ -	$ -	**467**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	12,725		12,725	$ 1,433	-	$ -	$ 212	$ 38	$ (12)	**1,670**
64540	54 Time of Use	38,592		38,592	$ 1,926	505	$ 3,155	$ 216	$ 116	$ -	**5,412**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 6,220	$ -	$ -	**6,220**
64700	70 Full Interruptable	33,055,514		33,055,514	$ 1,646,556	78,785	$ 374,228	$ 25,015	$ (59,500)	$ (745)	**1,985,553**
64701	71 Partial Interruptable	2,133,000		2,133,000	$ 105,459	9,509	$ 51,797	$ 2,779	$ (3,839)	$ (71)	**156,125**
63181	81 Cycled Air M*	185,820		185,820	$ (5,946)	-	$ -	$ -	$ -	$ -	**(5,946)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**131,362,927**	**104,308**	**131,258,619**	**$ 11,369,526**	**211,351**	**$ 1,525,705**	**$ 1,069,259**	**$ 215,962**	**$ (7,605)**	**14,172,847**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

June, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	66,286,271		66,286,271	$ 8,278,404	-	$ -	$ 871,128	$ 198,873	$ (5,815)	**9,342,590**
63200	32 Resl Dem Ctrl	19,387		19,387	$ 1,473	53	$ 703	$ 180	$ 58	$ -	**2,415**
63133	33 Resid Electric Vehicles	6,840		6,840	$ 541	-	$ -	$ -	$ 21	$ -	**562**
63036	36 Irrigation	62,427		62,427	$ 3,115	554	$ 14,596	$ 270	$ 200	$ -	**18,181**
63037	37 Irrigation	1,671,838		1,671,838	$ 83,425	21,180	$ 96,369	$ 11,509	$ (2,508)	$ -	**188,795**
64100	41 Sm Genl Serv	3,416,473	2,821	3,413,652	$ 424,453	-	$ -	$ 61,140	$ 9,871	$ (97)	**495,366**
62441-6244:	44(1-3) Street Lights	884,894		884,894	$ 156,581.14	-	$ -	$ -	$ 2,566	$ -	**159,148**
62440	44 Security Lgts	40,418		40,418	$ 9,172	-	$ -	$ -	$ 118	$ -	**9,290**
62444	44 Security Lgts - LED	4,260		4,260	$ 2,077	-	$ -	$ -	$ 13	$ -	**2,090**
62446	44 Street Lgts - LED	1,552		1,552	$ 469	-	$ -	$ -	$ 5	$ -	**474**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	40,887,251	106,560	40,780,691	$ 2,961,064	128,492	$ 1,553,520	$ 88,147	$ 122,356	$ (974)	**4,724,113**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	10,508		10,508	$ 988	-	$ -	$ -	$ 15	$ -	**1,002**
63151	51 Resid Energy Stg.	684,507		684,507	$ 29,550	-	$ -	$ -	$ 958	$ -	**30,509**
64151	51 Commer Energy Stg.	6,362		6,362	$ 280	-	$ -	$ -	$ 9	$ -	**289**
63152	52 Resid Interruptible	2,853,944		2,853,944	$ 156,977	-	$ -	$ -	$ 1,714	$ -	**158,691**
64152	52 Commer Interruptible	58,612		58,612	$ 3,224	-	$ -	$ -	$ 35	$ -	**3,259**
63900	Resid-Wellspring *	497,700		497,700	$ 1,991	-	$ -	$ -	$ -	$ -	**1,991**
63901	Resid-Wellspring Solar*	4,500		4,500	$ 90	-	$ -	$ -	$ -	$ -	**90**
64900	Comm-Wellspring *	121,100		121,100	$ 484	-	$ -	$ -	$ -	$ -	**484**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	12,748		12,748	$ 1,484	-	$ -	$ 214	$ 38	$ (12)	**1,724**
64540	54 Time of Use	59,952		59,952	$ 2,992	589	$ 3,106	$ 216	$ 180	$ -	**6,494**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 6,220	$ -	$ -	**6,220**
64700	70 Full Interruptable	35,521,428		35,521,428	$ 1,769,504	86,495	$ 410,850	$ 25,163	$ (63,939)	$ (748)	**2,140,830**
64701	71 Partial Interruptable	1,997,752		1,997,752	$ 99,347	9,715	$ 61,176	$ 2,788	$ (3,596)	$ (71)	**159,644**
63181	81 Cycled Air M*	534,324		534,324	$ (17,099)	-	$ -	$ -	$ -	$ -	**(17,099)**
63182	82&84 Cycled Air UM	-		-	$ (515,726)	-	$ -	$ -	$ -	$ -	**(515,726)**
	Total*	**154,487,424**	**109,381**	**154,378,043**	**$ 13,455,786**	**247,078**	**$ 2,140,321**	**$ 1,066,974**	**$ 266,988**	**$ (7,718)**	**16,922,351**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

July, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	86,908,760		86,908,760	$ 11,367,099	-	$ -	$ 872,002	$ 260,730	$ (5,857)	**12,493,973**
63200	32 Resl Dem Ctrl	15,038		15,038	$ 1,143	59	$ 862	$ 168	$ 45	$ -	**2,218**
63133	33 Resid Electric Vehicles	7,082		7,082	$ 588	-	$ -	$ -	$ 21	$ -	**609**
63036	36 Irrigation	62,811		62,811	$ 3,134	545	$ 14,367	$ 240	$ 201	$ -	**17,942**
63037	37 Irrigation	2,676,062		2,676,062	$ 133,535	22,614	$ 102,893	$ 11,532	$ (4,014)	$ -	**243,946**
64100	41 Sm Genl Serv	3,546,915	1,618	3,545,297	$ 452,071	-	$ -	$ 60,090	$ 10,250	$ (103)	**522,308**
62441-6244:	44(1-3) Street Lights	884,159		884,159	$ 156,469.94	-	$ -	$ -	$ 2,564	$ -	**159,034**
62440	44 Security Lgts	40,522		40,522	$ 9,196	-	$ -	$ -	$ 119	$ -	**9,315**
62444	44 Security Lgts - LED	4,228		4,228	$ 2,061	-	$ -	$ -	$ 13	$ -	**2,074**
62446	44 Street Lgts - LED	1,872		1,872	$ 594	-	$ -	$ -	$ 5	$ -	**599**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	40,553,354	109,440	40,443,914	$ 2,947,521	130,860	$ 1,604,347	$ 88,195	$ 121,349	$ (999)	**4,760,411**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	12,769		12,769	$ 1,200	-	$ -	$ -	$ 18	$ -	**1,218**
63151	51 Resid Energy Stg.	860,171		860,171	$ 37,766	-	$ -	$ -	$ 1,204	$ -	**38,970**
64151	51 Commer Energy Stg.	7,345		7,345	$ 323	-	$ -	$ -	$ 10	$ -	**333**
63152	52 Resid Interruptible	3,817,190		3,817,190	$ 209,955	-	$ -	$ -	$ 2,295	$ -	**212,250**
64152	52 Commer Interruptible	70,384		70,384	$ 3,871	-	$ -	$ -	$ 42	$ -	**3,913**
63900	Resid-Wellspring *	524,500		524,500	$ 2,098	-	$ -	$ -	$ -	$ -	**2,098**
63901	Resid-Wellspring Solar*	4,600		4,600	$ 92	-	$ -	$ -	$ -	$ -	**92**
64900	Comm-Wellspring *	116,700		116,700	$ 467	-	$ -	$ -	$ -	$ -	**467**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	17,254		17,254	$ 2,017	-	$ -	$ 216	$ 52	$ (12)	**2,273**
64540	54 Time of Use	111,456		111,456	$ 5,586	878	$ 7,877	$ 216	$ 334	$ -	**14,014**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 6,220	$ -	$ -	**6,220**
64700	70 Full Interruptable	37,195,761		37,195,761	$ 1,862,286	86,013	$ 408,568	$ 25,654	$ (66,952)	$ (760)	**2,228,797**
64701	71 Partial Interruptable	2,091,584		2,091,584	$ 103,965	9,952	$ 57,709	$ 2,788	$ (3,765)	$ (71)	**160,627**
63181	81 Cycled Air M*	1,185,640		1,185,640	$ (37,940)	-	$ -	$ -	$ -	$ -	**(37,940)**
63182	82&84 Cycled Air UM	-		-	$ (517,246)	-	$ -	$ -	$ -	$ -	**(517,246)**
	Total*	**178,884,717**	**111,058**	**178,773,659**	**$ 16,748,777**	**250,922**	**$ 2,196,624**	**$ 1,067,321**	**$ 324,523**	**$ (7,803)**	**20,329,441**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

August, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	REVENUE per Download
63100	31 Residential	100,379,522		100,379,522	$ 13,128,864	-	$ -	$ 873,620	$ 301,133	$ (5,917)	**14,297,700**
63200	32 Resl Dem Ctrl	18,233		18,233	$ 1,386	67	$ 981	$ 180	$ 55	$ -	**2,601**
63133	33 Resid Electric Vehicles	7,270		7,270	$ 603	-	$ -	$ -	$ 22	$ -	**625**
63036	36 Irrigation	52,830		52,830	$ 2,636	537	$ 14,144	$ 240	$ 169	$ -	**17,190**
63037	37 Irrigation	1,883,517		1,883,517	$ 93,988	22,018	$ 100,180	$ 11,520	$ (2,825)	$ -	**202,862**
64100	41 Sm Genl Serv	3,943,510	1,833	3,941,677	$ 498,825	-	$ -	$ 59,989	$ 11,400	$ (104)	**570,110**
62441-6244	44(1-3) Street Lights	884,614		884,614	$ 156,570.69	-	$ -	$ -	$ 2,566	$ -	**159,136**
62440	44 Security Lgts	40,425		40,425	$ 9,172	-	$ -	$ -	$ 119	$ -	**9,291**
62444	44 Security Lgts - LED	4,227		4,227	$ 2,060	-	$ -	$ -	$ 13	$ -	**2,073**
62446	44 Street Lgts - LED	2,425		2,425	$ 768	-	$ -	$ -	$ 7	$ -	**776**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	46,048,154	113,280	45,934,874	$ 3,309,934	135,354	$ 1,659,438	$ 88,382	$ 137,820	$ (1,047)	**5,194,527**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	14,853		14,853	$ 1,396	-	$ -	$ -	$ 21	$ -	**1,417**
63151	51 Resid Energy Stg.	997,359		997,359	$ 43,837	-	$ -	$ -	$ 1,396	$ -	**45,234**
64151	51 Commer Energy Stg.	8,516		8,516	$ 375	-	$ -	$ -	$ 12	$ -	**387**
63152	52 Resid Interruptible	4,514,448		4,514,448	$ 248,305	-	$ -	$ -	$ 2,715	$ -	**251,019**
64152	52 Commer Interruptible	81,783		81,783	$ 4,498	-	$ -	$ -	$ 49	$ -	**4,547**
63900	Resid-Wellspring *	539,200		539,200	$ 2,157	-	$ -	$ -	$ -	$ -	**2,157**
63901	Resid-Wellspring Solar*	4,800		4,800	$ 96	-	$ -	$ -	$ -	$ -	**96**
64900	Comm-Wellspring *	119,200		119,200	$ 477	-	$ -	$ -	$ -	$ -	**477**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	21,192		21,192	$ 2,517	-	$ -	$ 224	$ 64	$ (12)	**2,792**
64540	54 Time of Use	107,424		107,424	$ 5,395	702	$ 3,500	$ 216	$ 322	$ -	**9,433**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 6,237	$ -	$ 85	**6,323**
64700	70 Full Interruptable	37,681,591		37,681,591	$ 1,878,524	86,191	$ 409,415	$ 25,629	$ (67,827)	$ (779)	**2,244,961**
64701	71 Partial Interruptable	2,214,848		2,214,848	$ 110,151	9,842	$ 57,972	$ 2,788	$ (3,987)	$ (70)	**166,854**
63181	81 Cycled Air M*	1,647,587		1,647,587	$ (52,723)	-	$ -	$ -	$ -	$ -	**(52,723)**
63182	82&84 Cycled Air UM	-		-	$ (519,502)	-	$ -	$ -	$ -	$ -	**(519,502)**
	Total*	**198,906,741**	**115,113**	**198,791,628**	**$ 18,931,235**	**254,710**	**$ 2,245,630**	**$ 1,069,024**	**$ 383,243**	**$ (7,844)**	22,621,287

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

September, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW						
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	TOTAL REVENUE per Download
63100	31 Residential	86,869,119		86,869,119	$ 10,772,030	-	$ -	$ 873,428	$ 260,629	$ (5,832)	**11,900,255**
63200	32 Resl Dem Ctrl	16,720		16,720	$ 1,271	62	$ 767	$ 178	$ 50	$ -	**2,265**
63133	33 Resid Electric Vehicles	6,841		6,841	$ 579	-	$ -	$ -	$ 21	$ -	**599**
63036	36 Irrigation	28,040		28,040	$ 1,399	380	$ 5,886	$ 240	$ 90	$ -	**7,615**
63037	37 Irrigation	66,081		66,081	$ 3,298	1,834	$ 8,345	$ 11,520	$ (99)	$ -	**23,063**
64100	41 Sm Genl Serv	3,366,249	2,062	3,364,187	$ 386,807	-	$ -	$ 60,141	$ 9,726	$ (103)	**456,571**
62441-6244	44(1-3) Street Lights	883,262		883,262	$ 156,287.79	-	$ -	$ -	$ 2,562	$ -	**158,850**
62440	44 Security Lgts	40,413		40,413	$ 9,167	-	$ -	$ -	$ 119	$ -	**9,286**
62444	44 Security Lgts - LED	4,262		4,262	$ 2,078	-	$ -	$ -	$ 13	$ -	**2,091**
62446	44 Street Lgts - LED	3,214		3,214	$ 1,032	-	$ -	$ -	$ 9	$ -	**1,042**
64500	45 Emergency Unmet.	-		-	$ 550	-	$ -	$ -	$ -	$ -	**550**
64600	46 General Service	38,914,768	101,760	38,813,008	$ 2,831,329	131,695	$ 1,232,322	$ 88,405	$ 116,448	$ (1,429)	**4,267,075**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	12,331		12,331	$ 1,159	-	$ -	$ -	$ 17	$ -	**1,176**
63151	51 Resid Energy Stg.	772,907		772,907	$ 34,006	-	$ -	$ -	$ 1,083	$ -	**35,089**
64151	51 Commer Energy Stg.	5,973		5,973	$ 263	-	$ -	$ -	$ 8	$ -	**271**
63152	52 Resid Interruptible	3,475,595		3,475,595	$ 191,167	-	$ -	$ -	$ 2,087	$ -	**193,254**
64152	52 Commer Interruptible	54,321		54,321	$ 2,988	-	$ -	$ -	$ 33	$ -	**3,020**
63900	Resid-Wellspring *	523,700		523,700	$ 2,095	-	$ -	$ -	$ -	$ -	**2,095**
63901	Resid-Wellspring Solar*	4,600		4,600	$ 92	-	$ -	$ -	$ -	$ -	**92**
64900	Comm-Wellspring *	127,500		127,500	$ 510	-	$ -	$ -	$ -	$ -	**510**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	15,971		15,971	$ 1,849	-	$ -	$ 212	$ 48	$ (12)	**2,096**
64540	54 Time of Use	54,240		54,240	$ 2,770	691	$ 4,107	$ 216	$ 163	$ -	**7,256**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,827	$ -	$ 90	**4,917**
64700	70 Full Interruptable	34,365,125		34,365,125	$ 1,711,867	80,636	$ 383,019	$ 25,753	$ (61,857)	$ (726)	**2,058,056**
64701	71 Partial Interruptable	2,104,688		2,104,688	$ 104,592	9,984	$ 53,529	$ 2,788	$ (3,788)	$ (71)	**157,050**
63181	81 Cycled Air M*	1,079,397		1,079,397	$ (34,541)	-	$ -	$ -	$ -	$ -	**(34,541)**
63182	82&84 Cycled Air UM	-		-	$ (26)	-	$ -	$ -	$ -	$ -	**(26)**
	Total*	**171,060,120**	**103,822**	**170,956,298**	**$ 16,184,994**	**225,282**	**$ 1,687,975**	**$ 1,067,708**	**$ 327,360**	**$ (8,082)**	19,259,953

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

October, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	65,065,470		65,065,470	$ 7,598,829	-	$ -	$ 872,395	$ 195,190	$ (5,748)	**8,660,665**
63200	32 Resl Dem Ctrl	16,688		16,688	$ 1,268	50	$ 558	$ 180	$ 50	$ -	**2,056**
63133	33 Resid Electric Vehicles	8,924		8,924	$ 728	-	$ -	$ -	$ 27	$ -	**755**
63036	36 Irrigation	26,042		26,042	$ 1,299	383	$ 5,938	$ 240	$ 83	$ -	**7,561**
63037	37 Irrigation	54,971		54,971	$ 2,744	1,338	$ 6,088	$ 11,526	$ (83)	$ -	**20,275**
64100	41 Sm Genl Serv	3,159,947	1,954	3,157,993	$ 355,335	-	$ -	$ 60,234	$ 9,128	$ (103)	**424,593**
62441-6244	44(1-3) Street Lights	885,227		885,227	$ 156,597.85	-	$ -	$ -	$ 2,567	$ -	**159,165**
62440	44 Security Lgts	40,319		40,319	$ 9,145	-	$ -	$ -	$ 118	$ -	**9,264**
62444	44 Security Lgts - LED	4,253		4,253	$ 2,073	-	$ -	$ -	$ 13	$ -	**2,086**
62446	44 Street Lgts - LED	3,775		3,775	$ 1,239	-	$ -	$ -	$ 11	$ -	**1,249**
64500	45 Emergency Unmet.	-		-	$ 570	-	$ -	$ -	$ -	$ -	**570**
64600	46 General Service	36,064,430	106,560	35,957,870	$ 2,627,357	121,899	$ 1,116,595	$ 88,849	$ 107,878	$ (1,335)	**3,939,343**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	9,877		9,877	$ 928	-	$ -	$ -	$ 14	$ -	**942**
63151	51 Resid Energy Stg.	517,120		517,120	$ 22,753	-	$ -	$ -	$ 724	$ -	**23,477**
64151	51 Commer Energy Stg.	4,898		4,898	$ 216	-	$ -	$ -	$ 7	$ -	**222**
63152	52 Resid Interruptible	2,319,232		2,319,232	$ 127,568	-	$ -	$ -	$ 1,398	$ -	**128,966**
64152	52 Commer Interruptible	36,780		36,780	$ 2,023	-	$ -	$ -	$ 22	$ -	**2,045**
63900	Resid-Wellspring *	494,400		494,400	$ 1,978	-	$ -	$ -	$ -	$ -	**1,978**
63901	Resid-Wellspring Solar*	4,400		4,400	$ 88	-	$ -	$ -	$ -	$ -	**88**
64900	Comm-Wellspring *	141,100		141,100	$ 564	-	$ -	$ -	$ -	$ -	**564**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	16,049		16,049	$ 1,821	-	$ -	$ 216	$ 48	$ (12)	**2,073**
64540	54 Time of Use	36,816		36,816	$ 1,959	543	$ 3,992	$ 216	$ 110	$ -	**6,277**
64660	60 Standby Service	10,944		10,944	$ 4,130	318	$ 2,911	$ 51	$ 33	$ 24	**7,150**
64700	70 Full Interruptable	31,199,619		31,199,619	$ 1,554,929	74,156	$ 352,242	$ 25,742	$ (56,159)	$ (421)	**1,876,333**
64701	71 Partial Interruptable	1,931,400		1,931,400	$ 95,964	10,101	$ 56,409	$ 2,788	$ (3,477)	$ (70)	**151,614**
63181	81 Cycled Air M*	297,941		297,941	$ (9,534)	-	$ -	$ -	$ -	$ -	**(9,534)**
63182	82&84 Cycled Air UM	-		-	$ (13)	-	$ -	$ -	$ -	$ -	**(13)**
	Total*	**141,412,781**	**108,514**	**141,304,267**	**$ 12,562,933**	**208,788**	**$ 1,544,734**	**$ 1,062,437**	**$ 257,704**	**$ (7,666)**	**15,420,141**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

November, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW						
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**TOTAL REVENUE per Download**
63100	31 Residential	56,586,138		56,586,138	$ 6,608,719	-	$ -	$ 876,271	$ 169,705	$ (5,736)	**7,648,960**
63200	32 Resl Dem Ctrl	23,342		23,342	$ 1,774	59	$ 651	$ 180	$ 70	$ -	**2,675**
63133	33 Resid Electric Vehicles	8,435		8,435	$ 721	-	$ -	$ -	$ 25	$ -	**746**
63036	36 Irrigation	6,966		6,966	$ 348	278	$ 4,316	$ 240	$ 22	$ -	**4,926**
63037	37 Irrigation	34,652		34,652	$ 1,730	1,204	$ 5,477	$ 11,513	$ (52)	$ -	**18,668**
64100	41 Sm Genl Serv	3,242,991	4,304	3,238,687	$ 364,737	-	$ -	$ 60,345	$ 9,369	$ (105)	**434,346**
62441-6244	44(1-3) Street Lights	886,565		886,565	$ 156,805.01	-	$ -	$ -	$ 2,571	$ -	**159,376**
62440	44 Security Lgts	40,292		40,292	$ 9,139	-	$ -	$ -	$ 118	$ -	**9,258**
62444	44 Security Lgts - LED	4,283		4,283	$ 2,088	-	$ -	$ -	$ 13	$ -	**2,101**
62446	44 Street Lgts - LED	4,073		4,073	$ 1,336	-	$ -	$ -	$ 12	$ -	**1,348**
64500	45 Emergency Unmet.	-		-	$ 620	-	$ -	$ -	$ -	$ -	**620**
64600	46 General Service	35,245,669	161,760	35,083,909	$ 2,542,259	109,880	$ 1,006,458	$ 88,613	$ 105,248	$ (1,144)	**3,741,434**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	11,367		11,367	$ 1,069	-	$ -	$ -	$ 16	$ -	**1,084**
63151	51 Resid Energy Stg.	500,782		500,782	$ 22,034	-	$ -	$ -	$ 701	$ -	**22,735**
64151	51 Commer Energy Stg.	4,505		4,505	$ 198	-	$ -	$ -	$ 6	$ -	**205**
63152	52 Resid Interruptible	2,497,621		2,497,621	$ 137,379	-	$ -	$ -	$ 1,515	$ -	**138,894**
64152	52 Commer Interruptible	48,911		48,911	$ 2,690	-	$ -	$ -	$ 29	$ -	**2,720**
63900	Resid-Wellspring *	479,800		479,800	$ 1,919	-	$ -	$ -	$ -	$ -	**1,919**
63901	Resid-Wellspring Solar*	4,200		4,200	$ 84	-	$ -	$ -	$ -	$ -	**84**
64900	Comm-Wellspring *	152,500		152,500	$ 610	-	$ -	$ -	$ -	$ -	**610**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	16,193		16,193	$ 1,824	-	$ -	$ 216	$ 49	$ (12)	**2,077**
64540	54 Time of Use	45,408		45,408	$ 2,344	396	$ 2,801	$ 216	$ 136	$ -	**5,497**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,827	$ -	$ -	**4,827**
64700	70 Full Interruptable	29,456,002		29,456,002	$ 1,467,811	69,054	$ 328,007	$ 25,730	$ (53,021)	$ (432)	**1,768,095**
64701	71 Partial Interruptable	1,818,128		1,818,128	$ 90,282	9,606	$ 54,517	$ 2,788	$ (3,273)	$ (71)	**144,244**
63181	81 Cycled Air M*	20,427		20,427	$ (654)	-	$ -	$ -	$ -	$ -	**(654)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**130,482,323**	**166,064**	**130,316,259**	**$ 11,418,241**	**190,477**	**$ 1,402,227**	**$ 1,070,940**	**$ 233,262**	**$ (7,500)**	14,117,169

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

December, 2016

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	per Download
63100	31 Residential	65,006,261		65,006,261	$ 7,591,508	-	$ -	$ 876,368	$ 194,977	$ (5,751)	**8,657,101**
63200	32 Resl Dem Ctrl	34,034		34,034	$ 2,587	83	$ 924	$ 180	$ 102	$ -	**3,793**
63133	33 Resid Electric Vehicles	10,566		10,566	$ 906	-	$ -	$ -	$ 32	$ -	**938**
63036	36 Irrigation	583		583	$ 29	2	$ 41	$ 240	$ 2	$ -	**312**
63037	37 Irrigation	29,351		29,351	$ 1,465	65	$ 295	$ 11,565	$ (44)	$ -	**13,281**
64100	41 Sm Genl Serv	3,698,667	3,693	3,694,974	$ 416,103	-	$ -	$ 60,490	$ 10,689	$ (107)	**487,175**
62441-6244	44(1-3) Street Lights	886,771		886,771	$ 156,864.69	-	$ -	$ -	$ 2,572	$ -	**159,437**
62440	44 Security Lgts	40,238		40,238	$ 9,127	-	$ -	$ -	$ 118	$ -	**9,245**
62444	44 Security Lgts - LED	4,372		4,372	$ 2,131	-	$ -	$ -	$ 14	$ -	**2,145**
62446	44 Street Lgts - LED	4,504		4,504	$ 1,455	-	$ -	$ -	$ 13	$ -	**1,468**
64500	45 Emergency Unmet.	-		-	$ 620	-	$ -	$ -	$ -	$ -	**620**
64600	46 General Service	36,755,945	313,728	36,442,217	$ 2,638,032	109,494	$ 1,002,966	$ 89,244	$ 109,320	$ (965)	**3,838,598**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	16,451		16,451	$ 1,546	-	$ -	$ -	$ 23	$ -	**1,569**
63151	51 Resid Energy Stg.	713,028		713,028	$ 31,373	-	$ -	$ -	$ 998	$ -	**32,372**
64151	51 Commer Energy Stg.	10,243		10,243	$ 451	-	$ -	$ -	$ 14	$ -	**465**
63152	52 Resid Interruptible	3,606,457		3,606,457	$ 198,364	-	$ -	$ -	$ 2,178	$ -	**200,541**
64152	52 Commer Interruptible	128,013		128,013	$ 7,041	-	$ -	$ -	$ 77	$ -	**7,118**
63900	Resid-Wellspring *	497,700		497,700	$ 1,991	-	$ -	$ -	$ -	$ -	**1,991**
63901	Resid-Wellspring Solar*	4,400		4,400	$ 88	-	$ -	$ -	$ -	$ -	**88**
64900	Comm-Wellspring *	567,000		567,000	$ 2,268	-	$ -	$ -	$ -	$ -	**2,268**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	22,764		22,764	$ 2,542	-	$ -	$ 216	$ 68	$ (12)	**2,814**
64540	54 Time of Use	52,320		52,320	$ 2,637	536	$ 5,144	$ 216	$ 157	$ -	**8,154**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,537	$ -	$ -	**5,537**
64700	70 Full Interruptable	31,274,912		31,274,912	$ 1,557,963	64,940	$ 308,467	$ 25,849	$ (56,295)	$ (618)	**1,835,365**
64701	71 Partial Interruptable	1,528,040		1,528,040	$ 75,754	6,180	$ 43,374	$ 2,788	$ (2,750)	$ (72)	**119,094**
63181	81 Cycled Air M*	10		10	$ (0)	-	$ -	$ -	$ -	$ -	**(0)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**143,823,520**	**317,421**	**143,506,099**	**$ 12,703,221**	**181,301**	**$ 1,361,211**	**$ 1,072,693**	**$ 262,264**	**$ (7,525)**	15,391,864

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

Full Year 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW						
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincidental Demand	**TOTAL ADJUSTED REVENUE**
63100	31 Residential	829,224,018	-	829,224,018	100,319,325	-	-	10,599,564	2,984,860	(69,786)	-	113,833,962
63200	32 Resl Dem Ctrl	363,369	-	363,369	27,616	924	10,891	2,160	1,308	-	-	41,976
63133	33 Resid Electric Vehicle:	151,266	-	151,266	12,214	-	-	-	544	-	-	12,758
63036	36 Irrigation	278,339	-	278,339	13,889	3,075	63,162	2,880	1,002	-	-	80,934
63037	37 Irrigation	7,719,342	-	7,719,342	384,884	86,916	395,469	138,160	7,720	-	-	926,232
64100	41 Sm Genl Serv	42,395,341	33,474	42,361,867	4,913,331	-	-	730,467	156,273	(1,163)	-	5,798,908
62440	44 Street Lgts	473,369	-	473,369	107,317	-	-	-	1,712	-	-	109,028
62441	44-1 Street Lights	563,046	-	563,046	74,466	-	-	-	2,027	-	-	76,493
62442	44-2 Street Lights	2,578,728	-	2,578,728	476,913	-	-	-	9,285	-	-	486,198
62443	44-3 Street Lights	7,464,363	-	7,464,363	1,324,078	-	-	-	26,873	-	-	1,350,951
62444	44 Security Lgts - LED	55,139	-	55,139	26,684	-	-	-	206	-	-	26,890
62446	44 Street Lgts - LED	83,396	-	83,396	26,022	-	-	-	299	-	-	26,322
64500	45 Emergency Unmet.	-	-	-	7,600	-	-	-	-	-	-	7,600
64600	46 General Service	449,250,291	2,031,072	447,219,219	32,338,067	1,406,118	14,102,253	1,085,355	1,520,605	(13,271)	-	49,033,009
63047	47 Municipal	-	-	-	3,900	-	-	-	-	-	-	3,900
64690	49 Geotherm Heat Pump	174,817	-	174,817	16,433	-	-	-	350	-	-	16,782
63151	51 Resid Energy Stg.	9,550,109	-	9,550,109	420,079	-	-	-	21,010	-	-	441,089
64151	51 Commer Energy Stg.	100,032	-	100,032	4,401	-	-	-	220	-	-	4,621
63152	52 Resid Interruptible	43,540,312	-	43,540,312	2,394,079	-	-	-	283,836	-	-	2,677,914
64152	52 Commer Interruptible	1,055,923	-	1,055,923	58,077	-	-	-	6,864	-	-	64,940
63900	Resid-Wellspring *	5,968,000	-	5,968,000	23,872	-	-	-	-	-	-	23,872
63901	Resid-Wellspring Solar *	96,000	-	96,000	1,920	-	-	-	-	-	-	1,920
64900	Comm-Wellspring *	2,448,400	-	2,448,400	9,794	-	-	-	-	-	-	9,794
64901	Comm-Wellspring Solar*	30,000	-	30,000	600	-	-	-	-	-	-	600
63530	53 Time of Day	225,313	-	225,313	25,591	-	-	2,593	811	(144)	-	28,851
64540	54 Time of Use	1,122,840	-	1,122,840	56,729	8,057	76,160	2,592	3,818	-	-	139,299
64660	60 Standby Service	-	-	-	-	-	-	16,190	-	45,368	-	61,558
64700	70 Full Interruptable	385,448,294	-	385,448,294	19,195,307	881,417	4,186,731	305,631	346,903	(362)	-	24,034,211
64701	71 Partial Interruptable	23,426,200	-	23,426,200	1,164,262	108,086	651,308	33,592	21,084	333	-	1,870,577
63181	81 Cycled Air M*	4,134,188	-	4,134,188	(132,295)	-	-	-	-	-	-	(132,295)
63182	82&84 Cycled Air UM	-	-	-	(1,575,024)	-	-	-	-	-	-	(1,575,024)
	Total	**1,805,243,847**	**2,064,546**	**1,803,179,301**	**$ 161,720,130**	**2,494,593**	**$ 19,485,975**	**$ 12,919,182**	**$ 5,397,610**	**$ (39,025)**	**$ -**	**199,483,872**

*Note: kWh Sales total does not foot since rate 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

January, 2017

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	76,265,164		76,265,164	$ 8,907,347	-	$ -	$ 880,340	$ 274,502	$ (5,842)	**10,056,346**
63200	32 Resl Dem Ctrl	59,685		59,685	$ 4,536	114	$ 1,267	$ 180	$ 215	$ -	**6,198**
63133	33 Resid Electric Vehicles	11,271		11,271	$ 976	-	$ -	$ -	$ 41	$ -	**1,017**
63036	36 Irrigation	528		528	$ 26	1	$ 27	$ 240	$ 2	$ -	**296**
63037	37 Irrigation	7,165		7,165	$ 358	8	$ 35	$ 11,490	$ 7	$ -	**11,890**
64100	41 Sm Genl Serv	4,234,966	3,866	4,231,100	$ 476,591	-	$ -	$ 60,802	$ 15,612	$ (105)	**552,899**
62440	44 Security Lights	40,133		40,133	$ 9,103	-	$ -	$ -	$ 145	$ -	**9,248**
62441	44-1 Street Lights	47,358		47,358	$ 6,264	-	$ -	$ -	$ 170	$ -	**6,434**
62442	44-2 Street Lights	218,307		218,307	$ 40,423	-	$ -	$ -	$ 786	$ -	**41,209**
62443	44-3 Street Lights	621,337		621,337	$ 110,217	-	$ -	$ -	$ 2,237	$ -	**112,454**
62444	44-4 Security Lgts - LED	4,379		4,379	$ 2,135	-	$ -	$ -	$ 16	$ -	**2,151**
62446	44-6 Street Lgts - LED	4,737		4,737	$ 1,525	-	$ -	$ -	$ 17	$ -	**1,542**
64500	45 Emergency Unmet.	-		-	$ 600	-	$ -	$ -	$ -	$ -	**600**
64600	46 General Service	38,331,845	314,784	38,017,061	$ 2,728,136	107,251	$ 982,418	$ 89,417	$ 129,253	$ (969)	**3,928,254**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	26,913		26,913	$ 2,530	-	$ -	$ -	$ 54	$ -	**2,584**
63151	51 Resid Energy Stg.	1,019,446		1,019,446	$ 44,856	-	$ -	$ -	$ 2,242	$ -	**47,097**
64151	51 Commer Energy Stg.	16,971		16,971	$ 747	-	$ -	$ -	$ 37	$ -	**784**
63152	52 Resid Interruptible	5,182,739		5,182,739	$ 285,030	-	$ -	$ -	$ 33,862	$ -	**318,892**
64152	52 Commer Interruptible	193,526		193,526	$ 10,644	-	$ -	$ -	$ 1,258	$ -	**11,902**
63900	Resid-Wellspring *	509,900		509,900	$ 2,040	-	$ -	$ -	$ -	$ -	**2,040**
63901	Resid-Wellspring Solar*	4,400		4,400	$ 88	-	$ -	$ -	$ -	$ -	**88**
64900	Comm-Wellspring *	288,000		288,000	$ 1,152	-	$ -	$ -	$ -	$ -	**1,152**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	27,251		27,251	$ 3,052	-	$ -	$ 216	$ 98	$ (12)	**3,354**
64540	54 Time of Use	101,520		101,520	$ 5,066	781	$ 8,374	$ 216	$ 345	$ -	**14,001**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,617	$ -	$ -	**5,617**
64700	70 Full Interruptable	30,792,518		30,792,518	$ 1,533,805	64,332	$ 305,576	$ 25,849	$ 27,713	$ (607)	**1,892,335**
64701	71 Partial Interruptable	1,646,936		1,646,936	$ 81,822	6,075	$ 42,392	$ 2,788	$ 1,482	$ (73)	**128,412**
63181	81 Cycled Air Resid*	446		446	$ (14)	$ -	$ -	$ -	$ -	$ -	**(14)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**158,854,695**	**318,650**	**158,536,045**	**$14,259,428**	**178,562**	**$ 1,340,089**	**$ 1,077,154**	**$ 490,095**	**$ (7,609)**	**17,159,156**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

February, 2017

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	68,629,017		68,629,017	$ 8,015,716	-	$ -	$ 879,504	$ 247,069	$ (5,838)	**9,136,451**
63200	32 Resl Dem Ctrl	50,023		50,023	$ 3,802	100	$ 1,114	$ 180	$ 180	$ -	**5,276**
63133	33 Resid Electric Vehicles	11,729		11,729	$ 1,019	-	$ -	$ -	$ 42	$ -	**1,061**
63036	36 Irrigation	467		467	$ 23	1	$ 25	$ 240	$ 2	$ -	**290**
63037	37 Irrigation	6,740		6,740	$ 337	9	$ 42	$ 11,490	$ 6	$ -	**11,875**
64100	41 Sm Genl Serv	4,088,599	2,933	4,085,666	$ 460,075	-	$ -	$ 60,780	$ 15,078	$ (104)	**535,829**
62440	44 Security Lights	40,200		40,200	$ 9,118	-	$ -	$ -	$ 145	$ -	**9,264**
62441	44-1 Street Lights	47,358		47,358	$ 6,264	-	$ -	$ -	$ 170	$ -	**6,434**
62442	44-2 Street Lights	218,307		218,307	$ 40,423	-	$ -	$ -	$ 786	$ -	**41,209**
62443	44-3 Street Lights	621,253		621,253	$ 110,201	-	$ -	$ -	$ 2,237	$ -	**112,437**
62444	44 Security Lgts - LED	4,416		4,416	$ 2,153	-	$ -	$ -	$ 17	$ -	**2,169**
62446	44 Street Lgts - LED	4,759		4,759	$ 1,531	-	$ -	$ -	$ 17	$ -	**1,548**
64500	45 Emergency Unmet.	-		-	$ 620	-	$ -	$ -	$ -	$ -	**620**
64600	46 General Service	38,053,702	234,912	37,818,790	$ 2,708,029	103,855	$ 951,308	$ 89,515	$ 128,586	$ (1,009)	**3,876,429**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	19,518		19,518	$ 1,835	-	$ -	$ -	$ 39	$ -	**1,874**
63151	51 Resid Energy Stg.	979,086		979,086	$ 42,987	-	$ -	$ -	$ 2,154	$ -	**45,141**
64151	51 Commer Energy Stg.	15,777		15,777	$ 694	-	$ -	$ -	$ 35	$ -	**729**
63152	52 Resid Interruptible	4,714,522		4,714,522	$ 259,308	-	$ -	$ -	$ 30,671	$ -	**289,979**
64152	52 Commer Interruptible	147,142		147,142	$ 8,093	-	$ -	$ -	$ 956	$ -	**9,049**
63900	Resid-Wellspring *	501,300		501,300	$ 2,005	-	$ -	$ -	$ -	$ -	**2,005**
63901	Resid-Wellspring Solar*	4,500		4,500	$ 90	-	$ -	$ -	$ -	$ -	**90**
64900	Comm-Wellspring *	295,400		295,400	$ 1,182	-	$ -	$ -	$ -	$ -	**1,182**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	23,248		23,248	$ 2,598	-	$ -	$ 216	$ 84	$ (12)	**2,886**
64540	54 Time of Use	101,616		101,616	$ 5,118	681	$ 7,938	$ 216	$ 346	$ -	**13,618**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 5,617	$ -	$ -	**5,617**
64700	70 Full Interruptable	27,799,302		27,799,302	$ 1,384,466	65,114	$ 309,293	$ 26,086	$ 25,019	$ (564)	**1,744,300**
64701	71 Partial Interruptable	1,571,864		1,571,864	$ 78,059	6,205	$ 42,067	$ 2,788	$ 1,415	$ (72)	**124,256**
63181	81 Cycled Air Resid*	317		317	$ (10)	$ -	$ -	$ -	$ -	$ -	**(10)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**147,148,645**	**237,845**	**146,910,800**	**$13,146,110**	**175,966**	**$ 1,311,788**	**$ 1,076,631**	**$ 455,053**	**$ (7,599)**	**15,981,983**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

March, 2017

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	60,214,438		60,214,438	$ 7,032,867	-	$ -	$ 880,870	$ 216,761	$ (5,771)	**8,124,728**
63200	32 Resl Dem Ctrl	43,047		43,047	$ 3,272	99	$ 1,101	$ 180	$ 155	$ -	**4,708**
63133	33 Resid Electric Vehicles	11,162		11,162	$ 950	-	$ -	$ -	$ 40	$ -	**990**
63036	36 Irrigation	562		562	$ 28	5	$ 76	$ 240	$ 2	$ -	**346**
63037	37 Irrigation	7,130		7,130	$ 356	33	$ 149	$ 11,460	$ 7	$ -	**11,972**
64100	41 Sm Genl Serv	3,505,558	2,975	3,502,583	$ 394,269	-	$ -	$ 60,772	$ 12,921	$ (99)	**467,863**
62440	44 Security Lights	39,981		39,981	$ 9,068	-	$ -	$ -	$ 145	$ -	**9,213**
62441	44-1 Street Lights	47,376		47,376	$ 6,266	-	$ -	$ -	$ 171	$ -	**6,436**
62442	44-2 Street Lights	217,973		217,973	$ 40,357	-	$ -	$ -	$ 785	$ -	**41,142**
62443	44-3 Street Lights	622,613		622,613	$ 110,419	-	$ -	$ -	$ 2,242	$ -	**112,661**
62444	44 Security Lgts - LED	4,434		4,434	$ 2,162	-	$ -	$ -	$ 17	$ -	**2,179**
62446	44 Street Lgts - LED	4,834		4,834	$ 1,554	-	$ -	$ -	$ 17	$ -	**1,571**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -	**630**
64600	46 General Service	33,972,282	236,448	33,735,834	$ 2,440,181	101,920	$ 933,586	$ 89,576	$ 114,704	$ (986)	**3,577,061**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	15,995		15,995	$ 1,504	-	$ -	$ -	$ 32	$ -	**1,536**
63151	51 Resid Energy Stg.	853,865		853,865	$ 37,570	-	$ -	$ -	$ 1,879	$ -	**39,449**
64151	51 Commer Energy Stg.	8,789		8,789	$ 387	-	$ -	$ -	$ 19	$ -	**406**
63152	52 Resid Interruptible	4,022,356		4,022,356	$ 221,004	-	$ -	$ -	$ 26,172	$ -	**247,175**
64152	52 Commer Interruptible	111,065		111,065	$ 6,109	-	$ -	$ -	$ 722	$ -	**6,831**
63900	Resid-Wellspring *	489,600		489,600	$ 1,958	-	$ -	$ -	$ -	$ -	**1,958**
63901	Resid-Wellspring Solar*	5,300		5,300	$ 106	-	$ -	$ -	$ -	$ -	**106**
64900	Comm-Wellspring *	164,500		164,500	$ 658	-	$ -	$ -	$ -	$ -	**658**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	20,790		20,790	$ 2,324	-	$ -	$ 216	$ 75	$ (12)	**2,603**
64540	54 Time of Use	67,920		67,920	$ 3,484	631	$ 5,382	$ 216	$ 231	$ -	**9,313**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 4,937	$ -	$ -	**4,937**
64700	70 Full Interruptable	30,715,270		30,715,270	$ 1,530,357	65,788	$ 312,495	$ 26,086	$ 27,644	$ (564)	**1,896,017**
64701	71 Partial Interruptable	1,782,696		1,782,696	$ 88,542	7,475	$ 42,388	$ 2,788	$ 1,604	$ (73)	**135,249**
63181	81 Cycled Air Resid*	576		576	$ (18)	$ -	$ -	$ -	$ -	$ -	**(18)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**136,290,136**	**239,423**	**136,050,713**	**$11,936,737**	**175,951**	**$ 1,295,178**	**$ 1,077,341**	**$ 406,344**	**$ (7,505)**	**14,708,095**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

April, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	per Download
63100	31 Residential	56,247,922		56,247,922	$ 6,569,698	-	$ -	$ 880,763	$ 202,481	$ (5,730)	**7,647,213**
63200	32 Resl Dem Ctrl	34,353		34,353	$ 2,611	87	$ 960	$ 180	$ 124	$ -	**3,875**
63133	33 Resid Electric Vehicles	10,174		10,174	$ 906	-	$ -	$ -	$ 37	$ -	**943**
63036	36 Irrigation	6,717		6,717	$ 335	244	$ 3,780	$ 240	$ 24	$ -	**4,380**
63037	37 Irrigation	29,604		29,604	$ 1,478	879	$ 3,998	$ 11,580	$ 30	$ -	**17,086**
64100	41 Sm Genl Serv	3,272,102	2,933	3,269,169	$ 367,956	-	$ -	$ 60,716	$ 12,059	$ (92)	**440,638**
62440	44 Security Lights	39,705		39,705	$ 9,005	-	$ -	$ -	$ 144	$ -	**9,149**
62441	44-1 Street Lights	47,376		47,376	$ 6,266	-	$ -	$ -	$ 171	$ -	**6,436**
62442	44-2 Street Lights	217,042		217,042	$ 40,140	-	$ -	$ -	$ 781	$ -	**40,922**
62443	44-3 Street Lights	622,701		622,701	$ 110,436	-	$ -	$ -	$ 2,242	$ -	**112,678**
62444	44 Security Lgts - LED	4,540		4,540	$ 2,213	-	$ -	$ -	$ 17	$ -	**2,230**
62446	44 Street Lgts - LED	5,240		5,240	$ 1,686	-	$ -	$ -	$ 19	$ -	**1,705**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -	**630**
64600	46 General Service	32,250,020	234,912	32,015,108	$ 2,336,660	104,319	$ 955,559	$ 94,631	$ 109,199	$ (1,001)	**3,495,048**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	12,124		12,124	$ 1,140	-	$ -	$ -	$ 24	$ -	**1,164**
63151	51 Resid Energy Stg.	777,429		777,429	$ 34,207	-	$ -	$ -	$ 1,710	$ -	**35,917**
64151	51 Commer Energy Stg.	7,546		7,546	$ 332	-	$ -	$ -	$ 17	$ -	**349**
63152	52 Resid Interruptible	3,563,797		3,563,797	$ 196,018	-	$ -	$ -	$ 23,193	$ -	**219,211**
64152	52 Commer Interruptible	79,625		79,625	$ 4,379	-	$ -	$ -	$ 518	$ -	**4,897**
63900	Resid-Wellspring *	483,500		483,500	$ 1,934	-	$ -	$ -	$ -	$ -	**1,934**
63901	Resid-Wellspring Solar*	5,900		5,900	$ 118	-	$ -	$ -	$ -	$ -	**118**
64900	Comm-Wellspring *	128,200		128,200	$ 513	-	$ -	$ -	$ -	$ -	**513**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	17,728		17,728	$ 1,979	-	$ -	$ 221	$ 64	$ (12)	**2,252**
64540	54 Time of Use	34,032		34,032	$ 1,784	546	$ 4,040	$ 216	$ 116	$ -	**6,155**
64660	60 Standby Service	-		-	$ -	-	$ -	$ 17	$ -	$ 95	**112**
64700	70 Full Interruptable	29,759,743		29,759,743	$ 1,482,511	69,687	$ 331,015	$ 26,086	$ 26,784	$ (642)	**1,865,754**
64701	71 Partial Interruptable	1,772,384		1,772,384	$ 88,090	9,517	$ 51,666	$ 2,898	$ 1,595	$ (73)	**144,176**
63181	81 Cycled Air Resid*	571		571	$ (18)	$ -	$ -	$ -	$ -	$ -	**(18)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**128,811,904**	**237,845**	**128,574,059**	**$11,263,380**	**185,278**	**$ 1,351,019**	**$ 1,077,549**	**$ 381,347**	**$ (7,455)**	**14,065,839**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

May, 2017

(Accounting Month information downloaded from Orcom)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	**TOTAL REVENUE per Download**
63100	31 Residential	53,742,837		53,742,837	$ 6,275,534	-	$ -	$ 884,474	$ 193,466	$ (5,792)	**7,347,683**
63200	32 Resl Dem Ctrl	23,884		23,884	$ 1,815	55	$ 614	$ 180	$ 86	$ -	**2,695**
63133	33 Resid Electric Vehicles	11,081		11,081	$ 951	-	$ -	$ -	$ 40	$ -	**991**
63036	36 Irrigation	21,275		21,275	$ 1,062	462	$ 7,166	$ 240	$ 77	$ -	**8,544**
63037	37 Irrigation	108,560		108,560	$ 5,417	3,371	$ 15,337	$ 11,490	$ 109	$ -	**32,353**
64100	41 Sm Genl Serv	3,146,969	2,519	3,144,450	$ 353,879	-	$ -	$ 60,713	$ 11,598	$ (93)	**426,097**
62440	44 Security Lights	39,865		39,865	$ 9,041	-	$ -	$ -	$ 144	$ -	**9,186**
62441	44-1 Street Lights	47,376		47,376	$ 6,266	-	$ -	$ -	$ 171	$ -	**6,436**
62442	44-2 Street Lights	216,736		216,736	$ 40,086	-	$ -	$ -	$ 780	$ -	**40,867**
62443	44-3 Street Lights	622,767		622,767	$ 110,451	-	$ -	$ -	$ 2,242	$ -	**112,693**
62444	44 Security Lgts - LED	4,560		4,560	$ 2,223	-	$ -	$ -	$ 17	$ -	**2,240**
62446	44 Street Lgts - LED	5,406		5,406	$ 1,807	-	$ -	$ -	$ 19	$ -	**1,827**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -	**630**
64600	46 General Service	34,999,432	2,112	34,997,320	$ 2,542,973	116,714	$ 1,069,096	$ 89,871	$ 118,656	$ (1,095)	**3,819,502**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	10,471		10,471	$ 984	-	$ -	$ -	$ 21	$ -	**1,005**
63151	51 Resid Energy Stg.	622,207		622,207	$ 27,377	-	$ -	$ -	$ 1,369	$ -	**28,746**
64151	51 Commer Energy Stg.	6,069		6,069	$ 267	-	$ -	$ -	$ 13	$ -	**280**
63152	52 Resid Interruptible	2,664,764		2,664,764	$ 146,572	-	$ -	$ -	$ 17,345	$ -	**163,917**
64152	52 Commer Interruptible	53,574		53,574	$ 2,947	-	$ -	$ -	$ 348	$ -	**3,295**
63900	Resid-Wellspring *	477,500		477,500	$ 1,910	-	$ -	$ -	$ -	$ -	**1,910**
63901	Resid-Wellspring Solar*	5,800		5,800	$ 116	-	$ -	$ -	$ -	$ -	**116**
64900	Comm-Wellspring *	122,100		122,100	$ 488	-	$ -	$ -	$ -	$ -	**488**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	14,450		14,450	$ 1,620	-	$ -	$ 212	$ 52	$ (12)	**1,873**
64540	54 Time of Use	64,800		64,800	$ 3,348	523	$ 3,889	$ 216	$ 220	$ -	**7,673**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 5,150	**5,150**
64700	70 Full Interruptable	32,704,146		32,704,146	$ 1,628,923	77,812	$ 369,608	$ 25,080	$ 29,434	$ 196	**2,053,240**
64701	71 Partial Interruptable	2,153,960		2,153,960	$ 107,079	10,449	$ 58,137	$ 2,750	$ 1,939	$ 76	**169,981**
63181	81 Cycled Air Resid*	164,091		164,091	$ (5,251)	$ -	$ -	$ -	$ -	$ -	**(5,251)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**131,285,189**	**4,631**	**131,280,558**	**$11,268,892**	**209,386**	**$ 1,523,846**	**$ 1,075,226**	**$ 378,147**	**$ (1,571)**	**14,244,540**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

June, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	69,073,223		69,073,223	$ 8,626,761	-	$ -	$ 882,137	$ 248,651	$ (5,775)	**9,751,774**
63200	32 Resl Dem Ctrl	21,367		21,367	$ 1,624	55	$ 740	$ 180	$ 77	$ -	**2,621**
63133	33 Resid Electric Vehicles	11,245		11,245	$ 905	-	$ -	$ -	$ 40	$ -	**945**
63036	36 Irrigation	55,648		55,648	$ 2,777	464	$ 12,235	$ 240	$ 200	$ -	**15,452**
63037	37 Irrigation	1,002,776		1,002,776	$ 50,039	17,156	$ 78,059	$ 11,547	$ 1,003	$ -	**140,647**
64100	41 Sm Genl Serv	3,329,783	2,542	3,327,241	$ 413,291	-	$ -	$ 60,737	$ 12,274	$ (96)	**486,206**
62440	44 Security Lights	39,553		39,553	$ 8,970	-	$ -	$ -	$ 143	$ -	**9,113**
62441	44-1 Street Lights	46,818		46,818	$ 6,192	-	$ -	$ -	$ 169	$ -	**6,360**
62442	44-2 Street Lights	216,794		216,794	$ 40,092	-	$ -	$ -	$ 781	$ -	**40,873**
62443	44-3 Street Lights	622,833		622,833	$ 110,461	-	$ -	$ -	$ 2,242	$ -	**112,703**
62444	44 Security Lgts - LED	4,524		4,524	$ 2,205	-	$ -	$ -	$ 17	$ -	**2,222**
62446	44 Street Lgts - LED	5,628		5,628	$ 1,924	-	$ -	$ -	$ 20	$ -	**1,944**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -	**630**
64600	46 General Service	38,859,925	92,160	38,767,765	$ 2,820,525	130,829	$ 1,581,089	$ 89,718	$ 131,823	$ (1,306)	**4,621,849**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	11,405		11,405	$ 1,072	-	$ -	$ -	$ 23	$ -	**1,095**
63151	51 Resid Energy Stg.	749,931		749,931	$ 32,997	-	$ -	$ -	$ 1,650	$ -	**34,647**
64151	51 Commer Energy Stg.	6,168		6,168	$ 271	-	$ -	$ -	$ 14	$ -	**285**
63152	52 Resid Interruptible	3,104,707		3,104,707	$ 170,718	-	$ -	$ -	$ 20,209	$ -	**190,926**
64152	52 Commer Interruptible	55,484		55,484	$ 3,052	-	$ -	$ -	$ 361	$ -	**3,412**
63900	Resid-Wellspring *	498,300		498,300	$ 1,993	-	$ -	$ -	$ -	$ -	**1,993**
63901	Resid-Wellspring Solar*	8,200		8,200	$ 164	-	$ -	$ -	$ -	$ -	**164**
64900	Comm-Wellspring *	131,700		131,700	$ 527	-	$ -	$ -	$ -	$ -	**527**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	16,699		16,699	$ 1,938	-	$ -	$ 216	$ 60	$ (12)	**2,202**
64540	54 Time of Use	141,552		141,552	$ 7,063	933	$ 9,121	$ 216	$ 481	$ -	**16,882**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 6,434	**6,434**
64700	70 Full Interruptable	35,573,962		35,573,962	$ 1,771,716	85,295	$ 405,151	$ 25,080	$ 32,017	$ 191	**2,234,154**
64701	71 Partial Interruptable	2,174,848		2,174,848	$ 108,126	10,174	$ 61,980	$ 2,750	$ 1,957	$ 77	**174,891**
63181	81 Cycled Air Resid*	535,117		535,117	$ (17,124)	$ -	$ -	$ -	$ -	$ -	**(17,124)**
63182	82&84 Cycled Air UM	-		-	$ (522,717)	-	$ -	$ -	$ -	$ -	**(522,717)**
	Total*	**155,124,873**	**94,702**	**155,030,171**	**$13,646,567**	**244,906**	**$ 2,148,375**	**$ 1,072,821**	**$ 454,211**	**$ (487)**	**17,321,487**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

July, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	**REVENUE per Download**
63100	31 Residential	81,075,859		81,075,859	$ 10,603,453	-	$ -	$ 881,304	$ 291,844	$ (5,858)	**11,770,743**
63200	32 Resl Dem Ctrl	12,329		12,329	$ 937	58	$ 855	$ 180	$ 44	$ -	**2,016**
63133	33 Resid Electric Vehicles	10,759		10,759	$ 844	-	$ -	$ -	$ 39	$ -	**883**
63036	36 Irrigation	71,166		71,166	$ 3,551	524	$ 13,801	$ 240	$ 256	$ -	**17,849**
63037	37 Irrigation	3,424,673		3,424,673	$ 170,891	22,884	$ 104,122	$ 11,520	$ 3,425	$ -	**289,958**
64100	41 Sm Genl Serv	3,326,157	2,643	3,323,514	$ 420,492	-	$ -	$ 60,910	$ 12,260	$ (96)	**493,566**
62440	44 Security Lights	39,355		39,355	$ 8,925	-	$ -	$ -	$ 142	$ -	**9,067**
62441	44-1 Street Lights	46,614		46,614	$ 6,165	-	$ -	$ -	$ 168	$ -	**6,333**
62442	44-2 Street Lights	216,794		216,794	$ 40,092	-	$ -	$ -	$ 781	$ -	**40,873**
62443	44-3 Street Lights	623,185		623,185	$ 110,519	-	$ -	$ -	$ 2,244	$ -	**112,763**
62444	44 Security Lgts - LED	4,614		4,614	$ 2,250	-	$ -	$ -	$ 17	$ -	**2,267**
62446	44 Street Lgts - LED	5,785		5,785	$ 1,974	-	$ -	$ -	$ 21	$ -	**1,995**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -	**630**
64600	46 General Service	39,431,284	96,192	39,335,092	$ 2,854,249	132,812	$ 1,628,468	$ 89,891	$ 133,752	$ (1,203)	**4,705,157**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -	**330**
64690	49 Geotherm Heat Pump	11,142		11,142	$ 1,047	-	$ -	$ -	$ 22	$ -	**1,070**
63151	51 Resid Energy Stg.	851,722		851,722	$ 37,476	-	$ -	$ -	$ 1,874	$ -	**39,350**
64151	51 Commer Energy Stg.	5,941		5,941	$ 261	-	$ -	$ -	$ 13	$ -	**274**
63152	52 Resid Interruptible	3,490,268		3,490,268	$ 191,685	-	$ -	$ -	$ 22,751	$ -	**214,436**
64152	52 Commer Interruptible	59,119		59,119	$ 3,252	-	$ -	$ -	$ 384	$ -	**3,636**
63900	Resid-Wellspring *	510,400		510,400	$ 2,042	-	$ -	$ -	$ -	$ -	**2,042**
63901	Resid-Wellspring Solar*	9,100		9,100	$ 182	-	$ -	$ -	$ -	$ -	**182**
64900	Comm-Wellspring *	136,200		136,200	$ 545	-	$ -	$ -	$ -	$ -	**545**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	17,011		17,011	$ 2,000	-	$ -	$ 216	$ 61	$ (12)	**2,265**
64540	54 Time of Use	159,120		159,120	$ 7,940	885	$ 8,872	$ 216	$ 541	$ -	**17,569**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 6,626	**6,626**
64700	70 Full Interruptable	37,331,643		37,331,643	$ 1,865,982	84,063	$ 399,298	$ 25,080	$ 33,599	$ 170	**2,324,128**
64701	71 Partial Interruptable	2,050,176		2,050,176	$ 101,908	9,641	$ 63,102	$ 2,750	$ 1,845	$ 76	**169,682**
63181	81 Cycled Air Resid*	1,041,077		1,041,077	$ (33,314)	$ -	$ -	$ -	$ -	$ -	**(33,314)**
63182	82&84 Cycled Air UM	-		-	$ (525,330)	-	$ -	$ -	$ -	$ -	**(525,330)**
	Total*	**172,264,716**	**98,835**	**172,165,881**	**$ 15,881,027**	**250,866**	**$ 2,218,518**	**$ 1,072,307**	**$ 506,083**	**$ (298)**	**19,677,637**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

August, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	REVENUE
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	per Download
63100	31 Residential	90,662,750		90,662,750	$ 11,856,428	-	$ -	$ 883,072	$ 326,360	$ (5,927)	**13,059,933**
63200	32 Resl Dem Ctrl	18,379		18,379	$ 1,397	64	$ 942	$ 180	$ 66	$ -	**2,585**
63133	33 Resid Electric Vehicles	10,896		10,896	$ 853	-	$ -	$ -	$ 39	$ -	**892**
63036	36 Irrigation	42,234		42,234	$ 2,107	437	$ 11,515	$ 240	$ 152	$ -	**14,015**
63037	37 Irrigation	1,717,382		1,717,382	$ 85,697	21,978	$ 100,000	$ 11,571	$ 1,718	$ -	**198,986**
64100	41 Sm Genl Serv	3,705,984	2,925	3,703,059	$ 468,675	-	$ -	$ 60,927	$ 13,666	$ (101)	**543,167**
62440	44 Security Lights	39,255		39,255	$ 8,901	-	$ -	$ -	$ 142	$ -	**9,043**
62441	44-1 Street Lights	46,614		46,614	$ 6,165	-	$ -	$ -	$ 168	$ -	**6,333**
62442	44-2 Street Lights	215,642		215,642	$ 39,866	-	$ -	$ -	$ 776	$ -	**40,643**
62443	44-3 Street Lights	623,647		623,647	$ 110,605	-	$ -	$ -	$ 2,245	$ -	**112,850**
62444	44 Security Lgts - LED	4,656		4,656	$ 2,270	-	$ -	$ -	$ 17	$ -	**2,287**
62446	44 Street Lgts - LED	6,451		6,451	$ 2,193	-	$ -	$ -	$ 23	$ -	**2,216**
64500	45 Emergency Unmet.	-		-	$ 620	-	$ -	$ -	$ -	$ -	**620**
64600	46 General Service	44,398,617	95,040	44,303,577	$ 3,172,994	130,332	$ 1,597,872	$ 89,930	$ 150,641	$ (1,150)	**5,010,287**
63047	47 Municipal	-		-	$ 320	-	$ -	$ -	$ -	$ -	**320**
64690	49 Geotherm Heat Pump	13,914		13,914	$ 1,308	-	$ -	$ -	$ 28	$ -	**1,336**
63151	51 Resid Energy Stg.	910,304		910,304	$ 40,053	-	$ -	$ -	$ 2,003	$ -	**42,056**
64151	51 Commer Energy Stg.	6,893		6,893	$ 303	-	$ -	$ -	$ 15	$ -	**318**
63152	52 Resid Interruptible	3,899,907		3,899,907	$ 214,505	-	$ -	$ -	$ 25,406	$ -	**239,911**
64152	52 Commer Interruptible	67,054		67,054	$ 3,688	-	$ -	$ -	$ 436	$ -	**4,124**
63900	Resid-Wellspring *	518,200		518,200	$ 2,073	-	$ -	$ -	$ -	$ -	**2,073**
63901	Resid-Wellspring Solar*	10,000		10,000	$ 200	-	$ -	$ -	$ -	$ -	**200**
64900	Comm-Wellspring *	130,100		130,100	$ 520	-	$ -	$ -	$ -	$ -	**520**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	18,337		18,337	$ 2,182	-	$ -	$ 216	$ 66	$ (12)	**2,452**
64540	54 Time of Use	124,656		124,656	$ 6,220	930	$ 10,003	$ 216	$ 424	$ -	**16,863**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 6,523	**6,523**
64700	70 Full Interruptable	35,837,960		35,837,960	$ 1,774,876	80,850	$ 384,036	$ 25,146	$ 32,254	$ 195	**2,216,507**
64701	71 Partial Interruptable	2,226,456		2,226,456	$ 110,695	10,211	$ 71,048	$ 2,750	$ 2,004	$ 76	**186,573**
63181	81 Cycled Air Resid*	1,249,524		1,249,524	$ (39,985)	$ -	$ -	$ -	$ -	$ -	**(39,985)**
63182	82&84 Cycled Air UM	-		-	$ (525,508)	-	$ -	$ -	$ -	$ -	**(525,508)**
	Total*	**184,597,988**	**97,965**	**184,500,023**	**$ 17,350,274**	**244,802**	**$ 2,175,417**	**$ 1,074,248**	**$ 558,649**	**$ (395)**	**21,158,192**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

September, 2017

(Accounting Month information downloaded from Orcom)

		kWh				**KW**						**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue		**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments		**per Download**
63100	31 Residential	75,731,106		75,731,106	$ 9,356,842	-	$ -	$ 887,102	$ 272,610	$ (5,839)		**10,510,716**
63200	32 Resl Dem Ctrl	17,405		17,405	$ 1,323	60	$ 736	$ 180	$ 63	$ -		**2,301**
63133	33 Resid Electric Vehicles	13,259		13,259	$ 1,023	-	$ -	$ -	$ 48	$ -		**1,070**
63036	36 Irrigation	52,816		52,816	$ 2,636	458	$ 7,105	$ 240	$ 190	$ -		**10,170**
63037	37 Irrigation	1,277,787		1,277,787	$ 63,762	18,030	$ 82,036	$ 11,520	$ 1,278	$ -		**158,596**
64100	41 Sm Genl Serv	3,427,346	2,852	3,424,494	$ 393,445	-	$ -	$ 61,041	$ 12,635	$ (97)		**467,024**
62440	44 Security Lights	39,128		39,128	$ 8,842	-	$ -	$ -	$ 141	$ -		**8,984**
62441	44-1 Street Lights	46,614		46,614	$ 6,165	-	$ -	$ -	$ 168	$ -		**6,333**
62442	44-2 Street Lights	213,317		213,317	$ 39,426	-	$ -	$ -	$ 768	$ -		**40,194**
62443	44-3 Street Lights	623,698		623,698	$ 110,613	-	$ -	$ -	$ 2,245	$ -		**112,858**
62444	44 Security Lgts - LED	4,672		4,672	$ 2,234	-	$ -	$ -	$ 17	$ -		**2,252**
62446	44 Street Lgts - LED	7,370		7,370	$ 2,079	-	$ -	$ -	$ 26	$ -		**2,105**
64500	45 Emergency Unmet.	-		-	$ 630	-	$ -	$ -	$ -	$ -		**630**
64600	46 General Service	39,950,586	87,360	39,863,226	$ 2,884,300	129,669	$ 1,211,344	$ 90,243	$ 135,544	$ (1,169)		**4,320,261**
63047	47 Municipal	-		-	$ 320	-	$ -	$ -	$ -	$ -		**320**
64690	49 Geotherm Heat Pump	10,942		10,942	$ 1,029	-	$ -	$ -	$ 22	$ -		**1,050**
63151	51 Resid Energy Stg.	671,419		671,419	$ 29,520	-	$ -	$ -	$ 1,477	$ -		**30,997**
64151	51 Commer Energy Stg.	5,179		5,179	$ 228	-	$ -	$ -	$ 11	$ -		**239**
63152	52 Resid Interruptible	2,844,712		2,844,712	$ 156,469	-	$ -	$ -	$ 18,538	$ -		**175,007**
64152	52 Commer Interruptible	51,263		51,263	$ 2,820	-	$ -	$ -	$ 333	$ -		**3,153**
63900	Resid-Wellspring *	500,700		500,700	$ 2,003	-	$ -	$ -	$ -	$ -		**2,003**
63901	Resid-Wellspring Solar*	11,200		11,200	$ 224	-	$ -	$ -	$ -	$ -		**224**
64900	Comm-Wellspring *	127,300		127,300	$ 509	-	$ -	$ -	$ -	$ -		**509**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -		**50**
63530	53 Time of Day	15,207		15,207	$ 1,744	-	$ -	$ 216	$ 55	$ (12)		**2,003**
64540	54 Time of Use	114,960		114,960	$ 5,812	771	$ 6,410	$ 216	$ 391	$ -		**12,828**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 5,031		**5,031**
64700	70 Full Interruptable	34,227,595		34,227,595	$ 1,704,853	84,167	$ 399,794	$ 25,190	$ 30,805	$ 189		**2,160,830**
64701	71 Partial Interruptable	2,137,072		2,137,072	$ 106,272	10,760	$ 60,543	$ 2,750	$ 1,923	$ 76		**171,564**
63181	81 Cycled Air Resid*	629,022		629,022	$ (20,129)	$ -	$ -	$ -	$ -	$ -		**(20,129)**
63182	82&84 Cycled Air UM	-		-	$ (507)	-	$ -	$ -	$ -	$ -		**(507)**
	Total*	**161,483,453**	**90,212**	**161,393,241**	**$14,864,534**	**243,916**	**$ 1,767,967**	**$ 1,078,698**	**$ 479,290**	**$ (1,821)**		**18,188,668**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

October, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					TOTAL
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	69,409,890		69,409,890	$ 8,106,909	-	$ -	$ 884,326	$ 249,867	$ (5,828)	**9,235,273**
63200	32 Resl Dem Ctrl	16,524		16,524	$ 1,256	61	$ 674	$ 180	$ 59	$ -	**2,170**
63133	33 Resid Electric Vehicles	13,489		13,489	$ 1,048	-	$ -	$ -	$ 49	$ -	**1,097**
63036	36 Irrigation	25,306		25,306	$ 1,263	308	$ 4,768	$ 240	$ 91	$ -	**6,361**
63037	37 Irrigation	41,455		41,455	$ 2,069	1,509	$ 6,866	$ 11,533	$ 42	$ -	**20,510**
64100	41 Sm Genl Serv	3,197,301	2,237	3,195,064	$ 359,408	-	$ -	$ 60,991	$ 11,780	$ (93)	**432,088**
62440	44 Security Lights	38,858		38,858	$ 8,810	-	$ -	$ -	$ 140	$ -	**8,951**
62441	44-1 Street Lights	46,446		46,446	$ 6,142	-	$ -	$ -	$ 167	$ -	**6,310**
62442	44-2 Street Lights	210,597		210,597	$ 38,935	-	$ -	$ -	$ 758	$ -	**39,694**
62443	44-3 Street Lights	621,592		621,592	$ 110,279	-	$ -	$ -	$ 2,238	$ -	**112,516**
62444	44 Security Lgts - LED	4,710		4,710	$ 2,246	-	$ -	$ -	$ 18	$ -	**2,264**
62446	44 Street Lgts - LED	9,548		9,548	$ 2,739	-	$ -	$ -	$ 34	$ -	**2,773**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -	**660**
64600	46 General Service	36,868,990	113,280	36,755,710	$ 2,679,877	127,903	$ 1,171,590	$ 90,721	$ 124,976	$ (1,075)	**4,066,089**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	11,263		11,263	$ 1,059	-	$ -	$ -	$ 23	$ -	**1,081**
63151	51 Resid Energy Stg.	640,242		640,242	$ 28,171	-	$ -	$ -	$ 1,409	$ -	**29,579**
64151	51 Commer Energy Stg.	4,979		4,979	$ 219	-	$ -	$ -	$ 11	$ -	**230**
63152	52 Resid Interruptible	2,644,648		2,644,648	$ 145,317	-	$ -	$ -	$ 17,214	$ -	**162,531**
64152	52 Commer Interruptible	45,563		45,563	$ 2,506	-	$ -	$ -	$ 296	$ -	**2,802**
63900	Resid-Wellspring *	491,500		491,500	$ 1,966	-	$ -	$ -	$ -	$ -	**1,966**
63901	Resid-Wellspring Solar*	11,100		11,100	$ 222	-	$ -	$ -	$ -	$ -	**222**
64900	Comm-Wellspring *	123,700		123,700	$ 495	-	$ -	$ -	$ -	$ -	**495**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	15,406		15,406	$ 1,749	-	$ -	$ 216	$ 55	$ (12)	**2,008**
64540	54 Time of Use	67,272		67,272	$ 3,549	530	$ 4,042	$ 216	$ 229	$ -	**8,036**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 4,972	**4,972**
64700	70 Full Interruptable	31,337,126		31,337,126	$ 1,560,369	75,047	$ 356,475	$ 25,238	$ 28,203	$ 268	**1,970,552**
64701	71 Partial Interruptable	2,239,328		2,239,328	$ 111,332	10,486	$ 57,399	$ 2,860	$ 2,015	$ 84	**173,690**
63181	81 Cycled Air Resid*	495,464		495,464	$ (15,855)	$ -	$ -	$ -	$ -	$ -	**(15,855)**
63182	82&84 Cycled Air UM	-		-	$ (962)	-	$ -	$ -	$ -	$ -	**(962)**
	Total*	**147,510,533**	**115,517**	**147,395,016**	**$13,162,152**	**215,843**	**$ 1,601,813**	**$ 1,076,521**	**$ 439,675**	**$ (1,684)**	**16,278,476**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

November, 2017

(Accounting Month information downloaded from Orcom)

		kWh				**KW**					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	61,709,347		61,709,347	$ 7,205,527	-	$ -	$ 886,369	$ 222,017	$ (5,814)	**8,308,098**
63200	32 Resl Dem Ctrl	27,062		27,062	$ 2,057	77	$ 857	$ 180	$ 97	$ -	**3,192**
63133	33 Resid Electric Vehicles	16,804		16,804	$ 1,272	-	$ -	$ -	$ 60	$ -	**1,332**
63036	36 Irrigation	1,169		1,169	$ 58	165	$ 2,557	$ 240	$ 4	$ -	**2,859**
63037	37 Irrigation	75,765		75,765	$ 3,467	814	$ 3,702	$ 11,491	$ 76	$ -	**18,735**
64100	41 Sm Genl Serv	3,582,168	2,544	3,579,624	$ 402,848	-	$ -	$ 61,008	$ 13,203	$ (92)	**476,967**
62440	44 Security Lights	38,849		38,849	$ 8,808	-	$ -	$ -	$ 140	$ -	**8,948**
62441	44-1 Street Lights	46,446		46,446	$ 6,142	-	$ -	$ -	$ 167	$ -	**6,310**
62442	44-2 Street Lights	208,663		208,663	$ 38,547	-	$ -	$ -	$ 751	$ -	**39,298**
62443	44-3 Street Lights	619,424		619,424	$ 109,951	-	$ -	$ -	$ 2,230	$ -	**112,181**
62444	44 Security Lgts - LED	4,793		4,793	$ 2,285	-	$ -	$ -	$ 18	$ -	**2,303**
62446	44 Street Lgts - LED	11,487		11,487	$ 3,393	-	$ -	$ -	$ 41	$ -	**3,435**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -	**660**
64600	46 General Service	37,389,362	235,008	37,154,354	$ 2,665,696	110,617	$ 1,013,249	$ 91,012	$ 126,324	$ (1,045)	**3,895,238**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -	**325**
64690	49 Geotherm Heat Pump	14,173		14,173	$ 1,332	-	$ -	$ -	$ 28	$ -	**1,361**
63151	51 Resid Energy Stg.	646,425		646,425	$ 28,443	-	$ -	$ -	$ 1,422	$ -	**29,865**
64151	51 Commer Energy Stg.	6,599		6,599	$ 290	-	$ -	$ -	$ 15	$ -	**305**
63152	52 Resid Interruptible	3,341,826		3,341,826	$ 183,811	-	$ -	$ -	$ 21,977	$ -	**205,788**
64152	52 Commer Interruptible	90,534		90,534	$ 4,979	-	$ -	$ -	$ 588	$ -	**5,568**
63900	Resid-Wellspring *	490,000		490,000	$ 1,960	-	$ -	$ -	$ -	$ -	**1,960**
63901	Resid-Wellspring Solar*	10,200		10,200	$ 204	-	$ -	$ -	$ -	$ -	**204**
64900	Comm-Wellspring *	307,400		307,400	$ 1,230	-	$ -	$ -	$ -	$ -	**1,230**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	18,710		18,710	$ 2,100	-	$ -	$ 216	$ 67	$ (12)	**2,372**
64540	54 Time of Use	81,888		81,888	$ 4,172	470	$ 3,735	$ 216	$ 278	$ -	**8,402**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 4,937	**4,937**
64700	70 Full Interruptable	29,093,052		29,093,052	$ 1,449,259	64,810	$ 307,848	$ 25,300	$ 26,184	$ 402	**1,808,994**
64701	71 Partial Interruptable	1,968,488		1,968,488	$ 97,830	10,246	$ 56,757	$ 2,860	$ 1,772	$ 81	**159,300**
63181	81 Cycled Air Resid*	17,897		17,897	$ (573)	$ -	$ -	$ -	$ -	$ -	**(573)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**138,993,034**	**237,552**	**138,755,482**	**$12,226,124**	**187,199**	**$ 1,388,706**	**$ 1,078,892**	**$ 417,463**	**$ (1,543)**	**15,109,643**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

December, 2017

(Accounting Month information downloaded from Orcom)

		kWh				KW					**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	**per Download**
63100	31 Residential	66,462,465		66,462,465	$ 7,762,243	-	$ -	$ 889,304	$ 239,231	$ (5,773)	**8,885,005**
63200	32 Resl Dem Ctrl	39,311		39,311	$ 2,988	93	$ 1,031	$ 180	$ 142	$ -	**4,340**
63133	33 Resid Electric Vehicles	19,397		19,397	$ 1,468	-	$ -	$ -	$ 70	$ -	**1,537**
63036	36 Irrigation	451		451	$ 23	5	$ 107	$ 240	$ 2	$ -	**371**
63037	37 Irrigation	20,305		20,305	$ 1,014	247	$ 1,123	$ 11,468	$ 20	$ -	**13,625**
64100	41 Sm Genl Serv	3,578,408	2,505	3,575,903	$ 402,400	-	$ -	$ 61,071	$ 13,188	$ (94)	**476,565**
62440	44 Security Lights	38,487		38,487	$ 8,725	-	$ -	$ -	$ 139	$ -	**8,864**
62441	44-1 Street Lights	46,650		46,650	$ 6,169	-	$ -	$ -	$ 168	$ -	**6,337**
62442	44-2 Street Lights	208,556		208,556	$ 38,525	-	$ -	$ -	$ 751	$ -	**39,276**
62443	44-3 Street Lights	619,313		619,313	$ 109,927	-	$ -	$ -	$ 2,230	$ -	**112,157**
62444	44 Security Lgts - LED	4,841		4,841	$ 2,308	-	$ -	$ -	$ 18	$ -	**2,326**
62446	44 Street Lgts - LED	12,151		12,151	$ 3,617	-	$ -	$ -	$ 44	$ -	**3,661**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -	**660**
64600	46 General Service	34,744,246	288,864	34,455,382	$ 2,504,446	109,899	$ 1,006,674	$ 90,829	$ 117,147	$ (1,262)	**3,717,835**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -	**330**
64690	49 Geotherm Heat Pump	16,957		16,957	$ 1,594	-	$ -	$ -	$ 34	$ -	**1,628**
63151	51 Resid Energy Stg.	828,033		828,033	$ 36,422	-	$ -	$ -	$ 1,822	$ -	**38,244**
64151	51 Commer Energy Stg.	9,121		9,121	$ 401	-	$ -	$ -	$ 20	$ -	**421**
63152	52 Resid Interruptible	4,066,066		4,066,066	$ 223,644	-	$ -	$ -	$ 26,497	$ -	**250,141**
64152	52 Commer Interruptible	101,974		101,974	$ 5,609	-	$ -	$ -	$ 663	$ -	**6,271**
63900	Resid-Wellspring *	497,100		497,100	$ 1,988	-	$ -	$ -	$ -	$ -	**1,988**
63901	Resid-Wellspring Solar*	10,300		10,300	$ 206	-	$ -	$ -	$ -	$ -	**206**
64900	Comm-Wellspring *	493,800		493,800	$ 1,975	-	$ -	$ -	$ -	$ -	**1,975**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	20,476		20,476	$ 2,305	-	$ -	$ 216	$ 74	$ (12)	**2,583**
64540	54 Time of Use	63,504		63,504	$ 3,173	376	$ 4,355	$ 216	$ 216	$ -	**7,959**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 5,600	**5,600**
64700	70 Full Interruptable	30,275,977		30,275,977	$ 1,508,193	64,451	$ 306,143	$ 25,410	$ 27,248	$ 405	**1,867,399**
64701	71 Partial Interruptable	1,701,992		1,701,992	$ 84,506	6,847	$ 43,828	$ 2,860	$ 1,532	$ 78	**132,804**
63181	81 Cycled Air Resid*	86		86	$ (3)	$ -	$ -	$ -	$ -	$ -	**(3)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**142,878,681**	**291,369**	**142,587,312**	**$12,714,905**	**181,917**	**$ 1,363,261**	**$ 1,081,793**	**$ 431,254**	**$ (1,057)**	**15,590,156**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

Full Year 2018

(Accounting Month information downloaded from (Orcom (Jan/Feb) and UMAX (Mar/Dec))

		kWh				KW						**TOTAL**
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincidental Demand	**ADJUSTED REVENUE**
63100	31 Residential	867,819,897	-	867,819,897	105,192,123	-	-	10,703,322	1,041,328	(69,697)	-	116,867,077
63200	32 Resl Dem Ctrl	407,603	-	407,603	31,002	989.16	11,700	2,162	489	-	-	45,353
63133	33 Resid Electric Vehicles	332,257	-	332,257	25,456	-	-	-	398	-	-	25,854
63036	36 Irrigation	301,498	-	301,498	15,045	3,463.95	72,079	3,120	392	-	-	90,636
63037	37 Irrigation	8,585,963	-	8,585,963	428,476	81,869.37	372,508	137,754	23,185	-	-	961,923
64100	41 Sm Genl Serv	42,671,392	28,835	42,642,557	4,953,969	-	-	740,730	51,072	(1,177)	-	5,744,594
62440	44 Street Lgts	446,106	-	446,106	101,671	-	-	-	721	-	-	102,393
62441	44-1 Street Lights	523,536	-	523,536	69,245	-	-	-	890	-	-	70,135
62442	44-2 Street Lights	2,487,972	-	2,487,972	459,611	-	-	-	4,228	-	-	463,839
62443	44-3 Street Lights	7,432,586	-	7,432,586	1,318,836	-	-	-	12,632	-	-	1,331,468
62444	44 Security Lgts - LED	63,709	-	63,709	30,430	-	-	-	128	-	-	30,558
62445	44-5 Street Lgts - LED	8,056	-	8,056	1,181	-	-	-	15	-	-	1,196
62446	44 Street Lgts - LED	171,871	-	171,871	51,404	-	-	-	316	-	-	51,719
64500	45 Emergency Unmet.	-	-	-	7,888	-	-	-	-	-	-	7,888
64600	46 General Service	452,048,090	2,090,976	449,957,114	32,587,049	1,404,898.80	14,034,675	1,097,366	584,964	(67,161)	-	48,236,894
63047	47 Municipal	-	-	-	3,960	-	-	-	-	-	-	3,960
64690	49 Geotherm Heat Pump	203,303	-	203,303	19,110	-	-	-	671	-	-	19,781
63151	51 Resid Energy Stg.	10,750,523	-	10,750,523	472,804	-	-	-	23,647	-	-	496,451
64151	51 Commer Energy Stg.	102,715	-	102,715	4,520	-	-	-	226	-	-	4,745
63152	52 Resid Interruptible	47,853,706	-	47,853,706	2,631,711	-	-	406	243,786	-	-	2,875,902
64152	52 Commer Interruptible	1,224,491	-	1,224,491	67,348	-	-	-	6,245	-	-	73,593
63900	Resid-Wellspring *	6,039,300	-	6,039,300	4,112	-	-	-	-	-	-	4,112
63901	Resid-Wellspring Solar *	146,000	-	146,000	432	-	-	-	-	-	-	432
64900	Comm-Wellspring *	2,952,300	-	2,952,300	2,315	-	-	-	-	-	-	2,315
64901	Comm-Wellspring Solar*	30,000	-	30,000	100	-	-	-	-	-	-	100
63530	53 Time of Day	217,249	-	217,249	24,451	-	-	2,588	262	(144)	-	27,157
64540	54 Time of Use	1,143,456	-	1,143,456	57,058	7,338.24	73,531	2,592	1,486	-	-	134,668
64660	60 Standby Service	20,003	-	20,003	-	-	-	-	-	65,387	-	65,387
64700	70 Full Interruptable	384,258,036	-	384,258,036	19,174,924	870,612.08	4,132,948	307,000	997,973	(25,037)	25,908	24,613,715
64701	71 Partial Interruptable	25,529,544	-	25,529,544	1,275,031	102,789.51	522,326	35,310	66,377	(4,293)	167,938	2,062,689
63181	81 Cycled Air M*	5,181,693	-	5,181,693	(165,926)	-	-	-	-	-	-	(165,926)
63182	82&84 Cycled Air UM	-	-	-	(1,620,131)	-	-	-	-	-	-	(1,620,131)
	Total	**1,854,583,558**	**2,119,811**	**1,852,463,747**	**$ 167,225,205**	**2,471,961.11**	**$ 19,219,768**	**$ 13,032,349**	**$ 3,061,432**	**$ (102,121)**	**$ 193,846**	**202,630,479**

*Note: kWh Sales total does not foot since rate 81 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

January, 2018

(Accounting Month information downloaded from Orcom)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	kWh Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	**TOTAL REVENUE per Download**
63100	31 Residential	78,317,079		78,317,079	$ 9,148,742	-	$ -	$ 890,059	$ 94,065	$ (5,880)	**10,126,986**
63200	32 Resl Dem Ctrl	67,701		67,701	$ 5,145	118	$ 1,308	$ 180	$ 81	$ -	**6,714**
63133	33 Resid Electric Vehicles	21,576		21,576	$ 1,720	-	$ -	$ -	$ 26	$ -	**1,746**
63036	36 Irrigation	425		425	$ 21	1	$ 26	$ 240	$ 1	$ -	**288**
63037	37 Irrigation	7,772		7,772	$ 388	(54)	$ (244)	$ 11,505	$ 21	$ -	**11,670**
64100	41 Sm Genl Serv	4,329,447	3,059	4,326,388	$ 487,155	-	$ -	$ 61,530	$ 5,177	$ (99)	**553,763**
62440	44 Security Lights	38,476		38,476	$ 8,722	-	$ -	$ -	$ 62	$ -	**8,784**
62441	44-1 Street Lights	46,158		46,158	$ 6,104	-	$ -	$ -	$ 78	$ -	**6,183**
62442	44-2 Street Lights	208,553		208,553	$ 38,525	-	$ -	$ -	$ 354	$ -	**38,879**
62443	44-3 Street Lights	619,288		619,288	$ 109,934	-	$ -	$ -	$ 1,053	$ -	**110,987**
62444	44-4 Security Lgts - LED	4,878		4,878	$ 2,327	-	$ -	$ -	$ 9	$ -	**2,336**
62445	44-5 Street Lgts - LED	118		118	$ 20	-	$ -	$ -	$ 0	$ -	**20**
62446	44-6 Street Lgts - LED	12,670		12,670	$ 3,841	-	$ -	$ -	$ 21	$ -	**3,863**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -	**660**
64600	46 General Service	39,783,889	321,024	39,462,865	$ 2,813,889	108,500	$ 993,856	$ 91,152	$ 51,342	$ (1,001)	**3,949,238**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -	**330**
64690	49 Geotherm Heat Pump	26,804		26,804	$ 2,520	-	$ -	$ -	$ 88	$ -	**2,608**
63151	51 Resid Energy Stg.	1,092,389		1,092,389	$ 48,065	-	$ -	$ -	$ 2,403	$ -	**50,468**
64151	51 Commer Energy Stg.	14,923		14,923	$ 657	-	$ -	$ -	$ 33	$ -	**689**
63152	52 Resid Interruptible	5,424,444		5,424,444	$ 298,353	-	$ -	$ -	$ 27,776	$ -	**326,130**
64152	52 Commer Interruptible	174,652		174,652	$ 9,606	-	$ -	$ -	$ 891	$ -	**10,497**
63900	Resid-Wellspring *	516,600		516,600	$ 2,066	-	$ -	$ -	$ -	$ -	**2,066**
63901	Resid-Wellspring Solar*	10,900		10,900	$ 218	-	$ -	$ -	$ -	$ -	**218**
64900	Comm-Wellspring *	305,700		305,700	$ 1,223	-	$ -	$ -	$ -	$ -	**1,223**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	25,408		25,408	$ 2,825	-	$ -	$ 216	$ 30	$ (12)	**3,059**
64540	54 Time of Use	61,440		61,440	$ 3,066	382	$ 4,412	$ 216	$ 80	$ -	**7,773**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 5,750	**5,750**
64700	70 Full Interruptable	30,622,046		30,622,046	$ 1,525,303	63,342	$ 300,874	$ 25,410	$ 79,617	$ 402	**1,931,607**
64701	71 Partial Interruptable	1,775,480		1,775,480	$ 88,158	5,302	$ 40,998	$ 2,860	$ 4,616	$ 82	**136,713**
63181	81 Cycled Air Resid*	122		122	$ (4)	$ -	$ -	$ -	$ -	$ -	**(4)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	-
	Total*	**162,675,616**	**324,083**	**162,351,533**	**$ 14,609,628**	**177,591**	**$ 1,341,230**	**$ 1,083,368**	**$ 267,827**	**$ (758)**	**17,301,295**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

February, 2018

(Accounting Month information downloaded from Orcom)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	TOTAL REVENUE per Download
63100	31 Residential	69,354,635		69,354,635	$ 8,096,723	-	$ -	$ 891,735	$ 83,199	$ (5,839)	**9,065,818**
63200	32 Resl Dem Ctrl	61,474		61,474	$ 4,672	117	$ 1,297	$ 180	$ 74	$ -	**6,223**
63133	33 Resid Electric Vehicles	21,309		21,309	$ 1,701	-	$ -	$ -	$ 26	$ -	**1,726**
63036	36 Irrigation	382		382	$ 19	0	$ 6	$ 240	$ 0	$ -	**265**
63037	37 Irrigation	7,240		7,240	$ 362	16	$ 73	$ 11,460	$ 20	$ -	**11,914**
64100	41 Sm Genl Serv	3,979,157	2,835	3,976,322	$ 447,652	-	$ -	$ 61,383	$ 4,758	$ (101)	**513,691**
62440	44 Security Lights	38,250		38,250	$ 8,681	-	$ -	$ -	$ 62	$ -	**8,743**
62441	44-1 Street Lights	44,262		44,262	$ 5,855	-	$ -	$ -	$ 75	$ -	**5,930**
62442	44-2 Street Lights	208,454		208,454	$ 38,507	-	$ -	$ -	$ 354	$ -	**38,861**
62443	44-3 Street Lights	619,203		619,203	$ 109,918	-	$ -	$ -	$ 1,052	$ -	**110,970**
62444	44 Security Lgts - LED	4,967		4,967	$ 2,369	-	$ -	$ -	$ 9	$ -	**2,378**
62445	44-5 Street Lgts - LED	678		678	$ 99	-	$ -	$ -	$ 1	$ -	**100**
62446	44 Street Lgts - LED	12,686		12,686	$ 3,846	-	$ -	$ -	$ 21	$ -	**3,868**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -	**660**
64600	46 General Service	35,911,599	274,464	35,637,135	$ 2,568,958	102,127	$ 935,485	$ 91,483	$ 46,307	$ (989)	**3,641,244**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -	**330**
64690	49 Geotherm Heat Pump	21,774		21,774	$ 2,047	-	$ -	$ -	$ 72	$ -	**2,119**
63151	51 Resid Energy Stg.	1,055,553		1,055,553	$ 46,444	-	$ -	$ -	$ 2,322	$ -	**48,767**
64151	51 Commer Energy Stg.	13,949		13,949	$ 614	-	$ -	$ -	$ 31	$ -	**644**
63152	52 Resid Interruptible	5,083,120		5,083,120	$ 279,582	-	$ -	$ -	$ 26,032	$ -	**305,614**
64152	52 Commer Interruptible	165,752		165,752	$ 9,116	-	$ -	$ -	$ 845	$ -	**9,962**
63900	Resid-Wellspring *	511,300		511,300	$ 2,045	-	$ -	$ -	$ -	$ -	**2,045**
63901	Resid-Wellspring Solar*	10,700		10,700	$ 214	-	$ -	$ -	$ -	$ -	**214**
64900	Comm-Wellspring *	273,100		273,100	$ 1,092	-	$ -	$ -	$ -	$ -	**1,092**
64901	Comm-Wellspring Solar*	2,500		2,500	$ 50	-	$ -	$ -	$ -	$ -	**50**
63530	53 Time of Day	22,283		22,283	$ 2,401	-	$ -	$ 216	$ 28	$ (12)	**2,633**
64540	54 Time of Use	72,144		72,144	$ 3,600	506	$ 5,009	$ 216	$ 94	$ -	**8,919**
64660	60 Standby Service	-		-	$ -	-	$ -	$ -	$ -	$ 5,750	**5,750**
64700	70 Full Interruptable	27,669,400		27,669,400	$ 1,378,311	63,657	$ 302,372	$ 25,410	$ 71,940	$ 424	**1,778,458**
64701	71 Partial Interruptable	1,639,288		1,639,288	$ 81,400	5,332	$ 44,044	$ 2,860	$ 4,262	$ 80	**132,646**
63181	81 Cycled Air Resid*	303		303	$ (10) $	-	$ -	$ -	$ -	$ -	**(10)**
63182	82&84 Cycled Air UM	-		-	$ -	-	$ -	$ -	$ -	$ -	**-**
	Total*	**146,007,559**	**277,299**	**145,730,260**	**$ 13,097,258**	**171,756**	**$ 1,288,285**	**$ 1,085,182**	**$ 241,585**	**$ (687)**	**15,711,624**

*Note: kWh Sales total does not foot since rates 81 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

March, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	56,649,523		56,649,523	$ 6,617,777	-	$ -	$ 875,576	$ 67,985	$ (5,646)		**7,555,693**
63200	32 Resl Dem Ctrl	42,954		42,954	$ 3,267	83	$ 922	$ 177	$ 52	$ -		**4,418**
63133	33 Resid Electric Vehicles	17,602		17,602	$ 1,367	-	$ -	$ -	$ 21	$ -		**1,388**
63036	36 Irrigation	408		408	$ 21	0	$ 2	$ 240	$ 1	$ -		**263**
63037	37 Irrigation	6,918		6,918	$ 350	34	$ 156	$ 11,460	$ 19	$ -		**11,985**
64100	41 Sm Genl Serv	3,467,066	2,854	3,464,212	$ 391,237	-	$ -	$ 60,925	$ 4,158	$ (101)		**456,219**
62440	44 Security Lights	37,805		37,805	$ 8,650	-	$ -	$ -	$ 61	$ -		**8,711**
62441	44-1 Street Lights	42,552		42,552	$ 5,629	-	$ -	$ -	$ 72	$ -		**5,701**
62442	44-2 Street Lights	207,703		207,703	$ 38,376	-	$ -	$ -	$ 353	$ -		**38,728**
62443	44-3 Street Lights	621,208		621,208	$ 110,242	-	$ -	$ -	$ 1,056	$ -		**111,298**
62444	44 Security Lgts - LED	4,934		4,934	$ 2,364	-	$ -	$ -	$ 19	$ -		**2,383**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 3	$ -		**109**
62446	44 Street Lgts - LED	12,582		12,582	$ 3,828	-	$ -	$ -	$ 45	$ -		**3,873**
64500	45 Emergency Unmet.	-		-	$ 650	-	$ -	$ -	$ -	$ -		**650**
64600	46 General Service	34,069,999	221,952	33,848,047	$ 2,447,919	99,295	$ 910,077	$ 91,002	$ 44,003	$ (198)		**3,492,803**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	18,714		18,714	$ 1,759	-	$ -	$ -	$ 62	$ -		**1,821**
63151	51 Resid Energy Stg.	833,258		833,258	$ 36,665	-	$ -	$ -	$ 1,833	$ -		**38,498**
64151	51 Commer Energy Stg.	9,361		9,361	$ 412	-	$ -	$ -	$ 21	$ -		**432**
63152	52 Resid Interruptible	4,066,783		4,066,783	$ 223,685	-	$ -	$ 18	$ 20,689	$ -		**244,392**
64152	52 Commer Interruptible	119,193		119,193	$ 6,556	-	$ -	$ -	$ 608	$ -		**7,164**
63900	Resid-Wellspring *	475,200		475,200	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	10,600		10,600	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	240,400		240,400	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	21,836		21,836	$ 2,408	-	$ -	$ 214	$ 26	$ (12)		**2,636**
64540	54 Time of Use	82,944		82,944	$ 4,139	578	$ 5,378	$ 216	$ 108	$ -		**9,840**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 5,020		**5,020**
64700	70 Full Interruptable	29,653,518		29,653,518	$ 1,481,006	58,301	$ 274,470	$ 25,410	$ 77,099	$ -		**1,857,985**
64701	71 Partial Interruptable	1,719,928		1,719,928	$ 86,019	4,946	$ 23,035	$ 2,860	$ 4,472	$ -	$ 10,505	**126,891**
63181	81 Cycled Air Resid*	726		726	$ 2,329	$ -	$ -	$ -	$ -	$ -		**2,329**
63182	82&84 Cycled Air UM	-		-	$ 240	-	$ -	$ -	$ -	$ -		**240**
	Total*	**131,707,514**	**224,806**	**131,482,708**	**$ 11,477,331**	**163,238**	**$ 1,214,040**	**$ 1,068,098**	**$ 222,764**	**$ (937)**	**$ 10,505**	**13,991,801**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

April, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	63,041,013		63,041,013	$ 7,353,042	-	$ -	$ 888,742	$ 75,521	$ (5,764)		**8,311,542**
63200	32 Resl Dem Ctrl	43,930		43,930	$ 3,341	79	$ 872	$ 180	$ 53	$ -		**4,446**
63133	33 Resid Electric Vehicles	24,508		24,508	$ 2,228	-	$ -	$ -	$ 30	$ -		**2,257**
63036	36 Irrigation	533		533	$ 27	41	$ 628	$ 240	$ 1	$ -		**896**
63037	37 Irrigation	8,542		8,542	$ 432	345	$ 1,568	$ 11,425	$ 23	$ -		**13,448**
64100	41 Sm Genl Serv	3,600,561	2,522	3,598,039	$ 406,346	-	$ -	$ 60,852	$ 4,318	$ (96)		**471,421**
62440	44 Security Lights	38,104		38,104	$ 8,681	-	$ -	$ -	$ 62	$ -		**8,743**
62441	44-1 Street Lights	44,487		44,487	$ 5,882	-	$ -	$ -	$ 76	$ -		**5,958**
62442	44-2 Street Lights	207,535		207,535	$ 38,343	-	$ -	$ -	$ 353	$ -		**38,696**
62443	44-3 Street Lights	621,183		621,183	$ 110,234	-	$ -	$ -	$ 1,056	$ -		**111,289**
62444	44 Security Lgts - LED	4,992		4,992	$ 2,381	-	$ -	$ -	$ 10	$ -		**2,391**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	12,670		12,670	$ 3,850	-	$ -	$ -	$ 22	$ -		**3,871**
64500	45 Emergency Unmet.	-		-	$ 650	-	$ -	$ -	$ -	$ -		**650**
64600	46 General Service	34,880,815	206,688	34,674,127	$ 2,499,213	99,129	$ 917,858	$ 90,855	$ 45,076	$ (3,035)		**3,549,967**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	17,838		17,838	$ 1,677	-	$ -	$ -	$ 59	$ -		**1,736**
63151	51 Resid Energy Stg.	1,002,160		1,002,160	$ 44,053	-	$ -	$ -	$ 2,205	$ -		**46,257**
64151	51 Commer Energy Stg.	8,998		8,998	$ 396	-	$ -	$ -	$ 20	$ -		**416**
63152	52 Resid Interruptible	4,424,731		4,424,731	$ 243,373	-	$ -	$ 18	$ 22,530	$ -		**265,921**
64152	52 Commer Interruptible	122,440		122,440	$ 6,734	-	$ -	$ -	$ 624	$ -		**7,359**
63900	Resid-Wellspring *	490,100		490,100	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	11,100		11,100	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	193,200		193,200	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	20,614		20,614	$ 2,277	-	$ -	$ 216	$ 25	$ (12)		**2,506**
64540	54 Time of Use	93,840		93,840	$ 4,683	540	$ 4,733	$ 216	$ 122	$ -		**9,754**
64660	60 Standby Service	2,001		2,001	$ -	-	$ -	$ -	$ -	$ 5,025		**5,025**
64700	70 Full Interruptable	28,846,311		28,846,311	$ 1,440,667	69,103	$ 328,241	$ 25,410	$ 75,000	$ (2,581)		**1,866,737**
64701	71 Partial Interruptable	1,928,576		1,928,576	$ 96,431	7,610	$ 36,147	$ 2,970	$ 5,014	$ (485)	$ 9,943	**150,020**
63181	81 Cycled Air Resid*	-		-	$ (2,465)	$ -	$ -	$ -	$ -	$ -		**(2,465)**
63182	82&84 Cycled Air UM	-		-	$ (240)	-	$ -	$ -	$ -	$ -		**(240)**
	Total*	**138,995,107**	**209,210**	**138,785,897**	**$ 12,272,671**	**176,846**	**$ 1,290,048**	**$ 1,081,124**	**$ 232,200**	**$ (6,948)**	**$ 9,943**	**14,879,038**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

May, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	56,187,464		56,187,464	$ 6,565,895	-	$ -	$ 897,688	$ 67,434	$ (5,827)		**7,525,190**
63200	32 Resl Dem Ctrl	29,499		29,499	$ 2,244	67	$ 744	$ 180	$ 35	$ -		**3,203**
63133	33 Resid Electric Vehicles	20,913		20,913	$ 1,620	-	$ -	$ -	$ 25	$ -		**1,646**
63036	36 Irrigation	45,452		45,452	$ 2,268	464	$ 7,213	$ 270	$ 59	$ -		**9,810**
63037	37 Irrigation	249,365		249,365	$ 12,447	7,604	$ 34,598	$ 11,447	$ 674	$ -		**59,166**
64100	41 Sm Genl Serv	3,018,568	1,499	3,017,069	$ 341,813	-	$ -	$ 62,744	$ 3,632	$ (107)		**408,082**
62440	44 Security Lights	38,110		38,110	$ 8,702	-	$ -	$ -	$ 62	$ -		**8,764**
62441	44-1 Street Lights	43,536		43,536	$ 6,681	-	$ -	$ -	$ 86	$ -		**6,767**
62442	44-2 Street Lights	208,174		208,174	$ 46,343	-	$ -	$ -	$ 426	$ -		**46,769**
62443	44-3 Street Lights	621,190		621,190	$ 130,875	-	$ -	$ -	$ 1,240	$ -		**132,115**
62444	44 Security Lgts - LED	4,979		4,979	$ 2,388	-	$ -	$ -	$ 9	$ -		**2,397**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	12,667		12,667	$ 3,936	-	$ -	$ -	$ 22	$ -		**3,958**
64500	45 Emergency Unmet.	-		-	$ 650	-	$ -	$ -	$ -	$ -		**650**
64600	46 General Service	34,330,476	90,432	34,240,044	$ 2,519,992	131,695	$ 1,128,004	$ 92,452	$ 44,581	$ (7,768)		**3,777,261**
63047	47 Municipal	-		-	$ 335	-	$ -	$ -	$ -	$ -		**335**
64690	49 Geotherm Heat Pump	10,063		10,063	$ 946	-	$ -	$ -	$ 33	$ -		**979**
63151	51 Resid Energy Stg.	761,089		761,089	$ 33,489	-	$ -	$ -	$ 1,674	$ -		**35,163**
64151	51 Commer Energy Stg.	7,004		7,004	$ 308	-	$ -	$ -	$ 15	$ -		**324**
63152	52 Resid Interruptible	3,213,580		3,213,580	$ 176,783	-	$ -	$ 22	$ 16,342	$ -		**193,147**
64152	52 Commer Interruptible	73,302		73,302	$ 4,032	-	$ -	$ -	$ 374	$ -		**4,406**
63900	Resid-Wellspring *	477,500		477,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	10,700		10,700	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	133,600		133,600	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	13,941		13,941	$ 1,563	-	$ -	$ 216	$ 17	$ (12)		**1,783**
64540	54 Time of Use	73,440		73,440	$ 3,665	717	$ 5,541	$ 216	$ 95	$ -		**9,517**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 5,020		**5,020**
64700	70 Full Interruptable	34,741,023		34,741,023	$ 1,731,771	85,089	$ 404,171	$ 25,190	$ 90,187	$ (2,983)	$ -	**2,248,336**
64701	71 Partial Interruptable	2,519,360		2,519,360	$ 125,911	10,444	$ 49,611	$ 2,970	$ 6,550	$ (478)	$ 10,470	**195,034**
63181	81 Cycled Air Resid*	213,468		213,468	$ (6,831)	$ -	$ -	$ -	$ -	$ -		**(6,831)**
63182	82&84 Cycled Air UM	-		-	$ (99)	-	$ -	$ -	$ -	$ -		**(99)**
	Total*	**136,223,920**	**91,931**	**136,131,989**	**$ 11,717,835**	**236,080**	**$ 1,629,881**	**$ 1,093,395**	**$ 233,574**	**$ (12,155)**	**$ 10,470**	**14,673,080**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

June, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	77,910,014		77,910,014	$ 9,466,951	-	$ -	$ 891,732	$ 93,485	$ (5,870)		**10,446,297**
63200	32 Resl Dem Ctrl	16,121		16,121	$ 1,228	69	$ 844	$ 180	$ 19	$ -		**2,271**
63133	33 Resid Electric Vehicles	25,629		25,629	$ 1,647	-	$ -	$ -	$ 29	$ -		**1,676**
63036	36 Irrigation	47,841		47,841	$ 2,387	557	$ 13,797	$ 270	$ 62	$ -		**16,516**
63037	37 Irrigation	614,953		614,953	$ 30,689	14,375	$ 65,406	$ 11,459	$ 1,661	$ -		**109,214**
64100	41 Sm Genl Serv	3,443,473	2,210	3,441,263	$ 414,005	-	$ -	$ 61,287	$ 4,120	$ (86)		**479,326**
62440	44 Security Lights	38,079		38,079	$ 8,675	-	$ -	$ -	$ 62	$ -		**8,737**
62441	44-1 Street Lights	43,464		43,464	$ 4,825	-	$ -	$ -	$ 62	$ -		**4,887**
62442	44-2 Street Lights	207,610		207,610	$ 30,475	-	$ -	$ -	$ 281	$ -		**30,756**
62443	44-3 Street Lights	620,666		620,666	$ 89,499	-	$ -	$ -	$ 871	$ -		**90,370**
62444	44 Security Lgts - LED	4,979		4,979	$ 2,369	-	$ -	$ -	$ 9	$ -		**2,378**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	13,129		13,129	$ 3,875	-	$ -	$ -	$ 22	$ -		**3,897**
64500	45 Emergency Unmet.	-		-	$ 650	-	$ -	$ -	$ -	$ -		**650**
64600	46 General Service	41,940,913	91,872	41,849,041	$ 3,043,044	136,324	$ 1,524,346	$ 91,345	$ 54,335	$ (8,701)		**4,704,370**
63047	47 Municipal	-		-	$ 325	-	$ -	$ -	$ -	$ -		**325**
64690	49 Geotherm Heat Pump	13,039		13,039	$ 1,226	-	$ -	$ -	$ 43	$ -		**1,269**
63151	51 Resid Energy Stg.	874,403		874,403	$ 38,475	-	$ -	$ -	$ 1,924	$ -		**40,398**
64151	51 Commer Energy Stg.	6,788		6,788	$ 299	-	$ -	$ -	$ 15	$ -		**314**
63152	52 Resid Interruptible	3,503,343		3,503,343	$ 192,652	-	$ -	$ 29	$ 17,834	$ -		**210,515**
64152	52 Commer Interruptible	78,257		78,257	$ 4,304	-	$ -	$ -	$ 399	$ -		**4,703**
63900	Resid-Wellspring *	508,200		508,200	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	12,600		12,600	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	129,600		129,600	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	16,345		16,345	$ 1,892	-	$ -	$ 221	$ 20	$ (12)		**2,120**
64540	54 Time of Use	141,744		141,744	$ 7,073	796	$ 9,291	$ 216	$ 184	$ -		**16,764**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 6,490		**6,490**
64700	70 Full Interruptable	35,173,960		35,173,960	$ 1,749,050	84,704	$ 402,344	$ 25,378	$ 91,074	$ (3,010)	$ -	**2,264,835**
64701	71 Partial Interruptable	2,389,864		2,389,864	$ 119,449	10,900	$ 51,775	$ 2,970	$ 6,214	$ (490)	$ 14,145	**194,062**
63181	81 Cycled Air Resid*	863,749		863,749	$ (27,640)	$ -	$ -	$ -	$ -	$ -		**(27,640)**
63182	82&84 Cycled Air UM	-		-	$ (178,007)	-	$ -	$ -	$ -	$ -		**(178,007)**
	Total*	**167,125,338**	**94,082**	**167,031,256**	**$ 15,009,519**	**247,726**	**$ 2,067,802**	**$ 1,085,088**	**$ 272,725**	**$(11,680)**	**$ 14,145**	**18,437,600**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

July, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	kWh Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	92,663,962		92,663,962	$ 12,109,731	-	$ -	$ 895,035	$ 111,200	$ (5,990)		**13,109,976**
63200	32 Resl Dem Ctrl	18,834		18,834	$ 1,434	61	$ 898	$ 180	$ 23	$ -		**2,535**
63133	33 Resid Electric Vehicles	23,165		23,165	$ 1,979	-	$ -	$ -	$ 28	$ -		**2,006**
63036	36 Irrigation	72,733		72,733	$ 3,629	558	$ 14,713	$ 270	$ 95	$ -		**18,707**
63037	37 Irrigation	3,100,117		3,100,117	$ 154,697	22,112	$ 100,609	$ 11,497	$ 8,370	$ -		**275,173**
64100	41 Sm Genl Serv	3,652,631	1,520	3,651,111	$ 463,461	-	$ -	$ 61,811	$ 4,382	$ (101)		**529,553**
62440	44 Security Lights	37,549		37,549	$ 8,573	-	$ -	$ -	$ 61	$ -		**8,634**
62441	44-1 Street Lights	43,332		43,332	$ 5,731	-	$ -	$ -	$ 74	$ -		**5,805**
62442	44-2 Street Lights	207,100		207,100	$ 38,255	-	$ -	$ -	$ 352	$ -		**38,607**
62443	44-3 Street Lights	618,914		618,914	$ 109,808	-	$ -	$ -	$ 1,052	$ -		**110,859**
62444	44 Security Lgts - LED	5,191		5,191	$ 2,483	-	$ -	$ -	$ 10	$ -		**2,492**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	13,527		13,527	$ 3,936	-	$ -	$ -	$ 23	$ -		**3,959**
64500	45 Emergency Unmet.	-		-	$ 668		$ -	$ -	$ -	$ -		**668**
64600	46 General Service	43,463,071	98,400	43,364,671	$ 3,144,817	135,163	$ 1,657,108	$ 91,452	$ 56,374	$ (8,859)		**4,940,892**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	14,084		14,084	$ 1,324	-	$ -	$ -	$ 46	$ -		**1,370**
63151	51 Resid Energy Stg.	999,795		999,795	$ 43,992	-	$ -	$ -	$ 2,200	$ -		**46,192**
64151	51 Commer Energy Stg.	6,470		6,470	$ 285	-	$ -	$ -	$ 14	$ -		**299**
63152	52 Resid Interruptible	4,119,863		4,119,863	$ 226,604	-	$ -	$ 27	$ 20,965	$ -		**247,596**
64152	52 Commer Interruptible	80,542		80,542	$ 4,430	-	$ -	$ -	$ 411	$ -		**4,841**
63900	Resid-Wellspring *	537,200		537,200	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	14,500		14,500	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	131,500		131,500	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	17,954		17,954	$ 2,115	-	$ -	$ 215	$ 22	$ (12)		**2,340**
64540	54 Time of Use	163,632		163,632	$ 8,165	795	$ 10,734	$ 216	$ 213	$ -		**19,328**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 6,490		**6,490**
64700	70 Full Interruptable	37,349,811		37,349,811	$ 1,876,818	85,003	$ 403,762	$ 26,070	$ 97,003	$ (3,273)	$ 25,908	**2,426,289**
64701	71 Partial Interruptable	2,444,376		2,444,376	$ 122,169	10,315	$ 48,995	$ 2,970	$ 6,355	$ (509)	$ 29,279	**209,259**
63181	81 Cycled Air Resid*	1,336,411		1,336,411	$ (42,765)	$ -	$ -	$ -	$ -	$ -		**(42,765)**
63182	82&84 Cycled Air UM	-		-	$ (516,207)	-	$ -	$ -	$ -	$ -		**(516,207)**
	Total*	**189,117,380**	**99,920**	**189,017,460**	**$ 17,776,566**	**254,007**	**$ 2,236,820**	**$ 1,089,743**	**$ 309,273**	**$ (12,255)**	**$ 55,187**	**21,455,334**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

August, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	Usage (kWh)	DEA Own Use (kWh)	kWh NET (kWh)	Revenue Adjusted (kWh)	KW (KW)	Revenue (KW)	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	95,569,046		95,569,046	$ 12,502,819	-	$ -	$ 890,770	$ 114,684	$ (5,867)		**13,502,405**
63200	32 Resl Dem Ctrl	16,626		16,626	$ 1,266	66	$ 972	$ 180	$ 20	$ -		**2,438**
63133	33 Resid Electric Vehicles	25,891		25,891	$ 2,212	-	$ -	$ -	$ 31	$ -		**2,243**
63036	36 Irrigation	72,614		72,614	$ 3,623	558	$ 14,698	$ 270	$ 94	$ -		**18,686**
63037	37 Irrigation	4,173,975		4,173,975	$ 208,282	22,686	$ 103,222	$ 11,520	$ 11,270	$ -		**334,294**
64100	41 Sm Genl Serv	3,477,256	1,709	3,475,547	$ 441,192	-	$ -	$ 61,740	$ 4,171	$ (98)		**507,005**
62440	44 Security Lights	36,328		36,328	$ 8,274	-	$ -	$ -	$ 59	$ -		**8,332**
62441	44-1 Street Lights	43,233		43,233	$ 5,718	-	$ -	$ -	$ 74	$ -		**5,792**
62442	44-2 Street Lights	206,906		206,906	$ 38,219	-	$ -	$ -	$ 352	$ -		**38,570**
62443	44-3 Street Lights	618,167		618,167	$ 109,662	-	$ -	$ -	$ 1,051	$ -		**110,712**
62444	44 Security Lgts - LED	5,632		5,632	$ 2,686	-	$ -	$ -	$ 10	$ -		**2,696**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	14,297		14,297	$ 4,152	-	$ -	$ -	$ 24	$ -		**4,177**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -		**660**
64600	46 General Service	42,207,105	99,552	42,107,553	$ 3,037,527	131,359	$ 1,610,457	$ 91,460	$ 54,740	$ (8,778)		**4,785,406**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	15,002		15,002	$ 1,410	-	$ -	$ -	$ 50	$ -		**1,460**
63151	51 Resid Energy Stg.	970,127		970,127	$ 42,687	-	$ -	$ -	$ 2,134	$ -		**44,821**
64151	51 Commer Energy Stg.	7,092		7,092	$ 312	-	$ -	$ -	$ 16	$ -		**328**
63152	52 Resid Interruptible	4,041,975		4,041,975	$ 222,320	-	$ -	$ 44	$ 20,553	$ -		**242,918**
64152	52 Commer Interruptible	76,717		76,717	$ 4,219	-	$ -	$ -	$ 391	$ -		**4,611**
63900	Resid-Wellspring *	532,200		532,200	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	14,800		14,800	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	151,400		151,400	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	16,736		16,736	$ 1,970	-	$ -	$ 213	$ 20	$ (12)		**2,191**
64540	54 Time of Use	157,296		157,296	$ 7,849	981	$ 11,559	$ 216	$ 204	$ -		**19,828**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 6,490		**6,490**
64700	70 Full Interruptable	37,670,413		37,670,413	$ 1,879,796	83,259	$ 395,482	$ 25,630	$ 97,877	$ (3,345)	$ -	**2,395,440**
64701	71 Partial Interruptable	2,528,544		2,528,544	$ 126,369	10,505	$ 49,901	$ 2,970	$ 6,574	$ (499)	$ 25,972	**211,287**
63181	81 Cycled Air Resid*	1,324,027		1,324,027	$ (42,369)	$ -	$ -	$ -	$ -	$ -		**(42,369)**
63182	82&84 Cycled Air UM	-		-	$ (519,342)	-	$ -	$ -	$ -	$ -		**(519,342)**
	Total*	**191,951,704**	**101,261**	**191,850,443**	**$ 18,091,949**	**249,415**	**$ 2,186,291**	**$ 1,085,013**	**$ 314,400**	**$ (12,109)**	**$ 25,972**	**21,691,517**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

September, 2018

(Accounting Month information downloaded from UMAX)

		kWh				KW						TOTAL
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	REVENUE per Download
63100	31 Residential	84,031,403		84,031,403	$ 10,640,430	-	$ -	$ 893,705	$ 100,839	$ (5,876)		**11,629,097**
63200	32 Resl Dem Ctrl	17,694		17,694	$ 1,347	68	$ 930	$ 168	$ 21	$ -		**2,467**
63133	33 Resid Electric Vehicles	27,432		27,432	$ 1,597	-	$ -	$ -	$ 33	$ -		**1,630**
63036	36 Irrigation	40,248		40,248	$ 2,008	548	$ 9,555	$ 270	$ 52	$ -		**11,886**
63037	37 Irrigation	241,132		241,132	$ 12,036	9,806	$ 44,617	$ 11,490	$ 651	$ -		**68,794**
64100	41 Sm Genl Serv	3,576,773	1,980	3,574,793	$ 425,989	-	$ -	$ 61,842	$ 4,291	$ (103)		**492,020**
62440	44 Security Lights	36,021		36,021	$ 8,222	-	$ -	$ -	$ 58	$ -		**8,281**
62441	44-1 Street Lights	43,128		43,128	$ 5,705	-	$ -	$ -	$ 73	$ -		**5,778**
62442	44-2 Street Lights	206,730		206,730	$ 38,187	-	$ -	$ -	$ 351	$ -		**38,539**
62443	44-3 Street Lights	618,154		618,154	$ 109,662	-	$ -	$ -	$ 1,051	$ -		**110,713**
62444	44 Security Lgts - LED	5,711		5,711	$ 2,730	-	$ -	$ -	$ 11	$ -		**2,741**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	15,055		15,055	$ 4,421	-	$ -	$ -	$ 26	$ -		**4,447**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -		**660**
64600	46 General Service	42,977,618	87,360	42,890,258	$ 3,113,081	134,009	$ 1,358,859	$ 91,580	$ 55,757	$ (7,960)		**4,611,318**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	14,427		14,427	$ 1,356	-	$ -	$ -	$ 48	$ -		**1,404**
63151	51 Resid Energy Stg.	862,054		862,054	$ 37,932	-	$ -	$ -	$ 1,897	$ -		**39,829**
64151	51 Commer Energy Stg.	5,674		5,674	$ 250	-	$ -	$ -	$ 12	$ -		**262**
63152	52 Resid Interruptible	3,561,537		3,561,537	$ 195,896	-	$ -	$ 36	$ 18,148	$ -		**214,079**
64152	52 Commer Interruptible	63,151		63,151	$ 3,473	-	$ -	$ -	$ 322	$ -		**3,795**
63900	Resid-Wellspring *	519,300		519,300	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	14,400		14,400	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	168,700		168,700	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	16,108		16,108	$ 1,849	-	$ -	$ 218	$ 19	$ (12)		**2,075**
64540	54 Time of Use	134,160		134,160	$ 6,695	882	$ 8,436	$ 216	$ 174	$ -		**15,521**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 5,020		**5,020**
64700	70 Full Interruptable	33,196,188		33,196,188	$ 1,654,936	83,037	$ 394,428	$ 25,652	$ 86,157	$ (2,968)	$ -	**2,158,205**
64701	71 Partial Interruptable	2,408,936		2,408,936	$ 120,400	11,231	$ 53,346	$ 2,970	$ 6,263	$ (494)	$ 25,875	**208,361**
63181	81 Cycled Air Resid*	1,062,795		1,062,795	$ (34,009)	$ -	$ -	$ -	$ -	$ -		**(34,009)**
63182	82&84 Cycled Air UM	-		-	$ (347,958)	-	$ -	$ -	$ -	$ -		**(347,958)**
	Total*	**172,100,060**	**89,340**	**172,010,720**	**$ 16,007,333**	**239,581**	**$ 1,870,172**	**$ 1,088,148**	**$ 276,256**	**$ (12,393)**	**$ 25,875**	**19,255,390**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

Dakota Electric Association

SALES BY RATE (Billed)

October, 2018

(Accounting Month information downloaded from UMAX)

		kWh				KW						**TOTAL**
			DEA	kWh	Revenue			Fixed		Revenue	Coincindental	**REVENUE**
Account	Rate	Usage	Own Use	NET	Adjusted	KW	Revenue	Charges	RTA	Adjustments	Demand	**per Download**
63100	31 Residential	67,744,229		67,744,229	$ 7,928,328	-	$ -	$ 898,157	$ 81,297	$ (5,849)		**8,901,933**
63200	32 Resl Dem Ctrl	19,656		19,656	$ 1,496	66	$ 744	$ 191	$ 24	$ -		**2,454**
63133	33 Resid Electric Vehicles	33,038		33,038	$ 2,496	-	$ -	$ -	$ 40	$ -		**2,536**
63036	36 Irrigation	15,257		15,257	$ 761	432	$ 6,692	$ 270	$ 20	$ -		**7,743**
63037	37 Irrigation	39,209		39,209	$ 1,961	1,344	$ 6,115	$ 11,510	$ 106	$ -		**19,693**
64100	41 Sm Genl Serv	3,029,247	1,883	3,027,364	$ 341,986	-	$ -	$ 62,133	$ 3,634	$ (94)		**407,658**
62440	44 Security Lights	35,912		35,912	$ 8,197	-	$ -	$ -	$ 58	$ -		**8,255**
62441	44-1 Street Lights	42,798		42,798	$ 5,657	-	$ -	$ -	$ 73	$ -		**5,730**
62442	44-2 Street Lights	206,542		206,542	$ 38,153	-	$ -	$ -	$ 351	$ -		**38,504**
62443	44-3 Street Lights	618,154		618,154	$ 109,662	-	$ -	$ -	$ 1,051	$ -		**110,713**
62444	44 Security Lgts - LED	5,725		5,725	$ 2,737	-	$ -	$ -	$ 11	$ -		**2,748**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	16,781		16,781	$ 4,975	-	$ -	$ -	$ 29	$ -		**5,004**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -		**660**
64600	46 General Service	33,274,847	114,912	33,159,935	$ 2,423,483	114,454	$ 1,048,973	$ 91,574	$ 43,108	$ (6,834)		**3,600,304**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	14,608		14,608	$ 1,373	-	$ -	$ -	$ 48	$ -		**1,421**
63151	51 Resid Energy Stg.	678,919		678,919	$ 29,874	-	$ -	$ -	$ 1,494	$ -		**31,368**
64151	51 Commer Energy Stg.	4,170		4,170	$ 183	-	$ -	$ -	$ 9	$ -		**193**
63152	52 Resid Interruptible	2,880,182		2,880,182	$ 158,422	-	$ -	$ 69	$ 14,610	$ -		**173,101**
64152	52 Commer Interruptible	52,723		52,723	$ 2,900	-	$ -	$ -	$ 269	$ -		**3,169**
63900	Resid-Wellspring *	505,400		505,400	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	13,000		13,000	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	168,400		168,400	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	13,214		13,214	$ 1,482	-	$ -	$ 204	$ 16	$ (12)		**1,690**
64540	54 Time of Use	56,160		56,160	$ 2,802	381	$ 2,638	$ 216	$ 73	$ -		**5,729**
64660	60 Standby Service	2,002		2,002	$ -	-	$ -	$ -	$ -	$ 3,562		**3,562**
64700	70 Full Interruptable	30,335,042		30,335,042	$ 1,510,975	72,629	$ 344,990	$ 25,630	$ 78,657	$ (2,608)	$ -	**1,957,645**
64701	71 Partial Interruptable	2,396,088		2,396,088	$ 119,759	10,655	$ 50,609	$ 2,970	$ 6,230	$ (483)	$ 24,079	**203,164**
63181	81 Cycled Air Resid*	370,025		370,025	$ (11,841)	$ -	$ -	$ -	$ -	$ -		**(11,841)**
63182	82&84 Cycled Air UM	-		-	$ (34,526)	-	$ -	$ -	$ -	$ -		**(34,526)**
	Total*	**141,513,228**	**116,795**	**141,396,433**	**$ 12,652,395**	**199,961**	**$ 1,460,760**	**$ 1,092,924**	**$ 231,206**	**$ (12,318)**	**$ 24,079**	**15,449,047**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

November, 2018

(Accounting Month information downloaded from UMAX)

Account	Rate	kWh Usage	kWh DEA Own Use	kWh NET	Revenue Adjusted	KW	KW Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	58,638,849		58,638,849	$ 6,851,113	-	$ -	$ 894,772	$ 70,368	$ (5,538)		**7,810,715**
63200	32 Resl Dem Ctrl	26,390		26,390	$ 2,008	80	$ 885	$ 180	$ 32	$ -		**3,105**
63133	33 Resid Electric Vehicles	41,454		41,454	$ 3,129	-	$ -	$ -	$ 50	$ -		**3,179**
63036	36 Irrigation	3,796		3,796	$ 189	296	$ 4,586	$ 270	$ 5	$ -		**5,051**
63037	37 Irrigation	113,248		113,248	$ 5,657	2,886	$ 13,133	$ 11,502	$ 306	$ -		**30,598**
64100	41 Sm Genl Serv	3,425,538	3,186	3,422,352	$ 379,490	-	$ -	$ 61,885	$ 4,037	$ (95)		**445,316**
62440	44 Security Lights	35,761		35,761	$ 8,143	-	$ -	$ -	$ 58	$ -		**8,201**
62441	44-1 Street Lights	43,458		43,458	$ 5,752	-	$ -	$ -	$ 74	$ -		**5,826**
62442	44-2 Street Lights	206,275		206,275	$ 38,098	-	$ -	$ -	$ 351	$ -		**38,449**
62443	44-3 Street Lights	618,127		618,127	$ 109,649	-	$ -	$ -	$ 1,051	$ -		**110,700**
62444	44 Security Lgts - LED	5,830		5,830	$ 2,780	-	$ -	$ -	$ 11	$ -		**2,791**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	17,578		17,578	$ 5,250	-	$ -	$ -	$ 30	$ -		**5,280**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -		**660**
64600	46 General Service	35,051,471	242,016	34,809,455	$ 2,513,011	107,714	$ 986,662	$ 91,365	$ 45,252	$ (6,481)		**3,629,809**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	16,062		16,062	$ 1,510	-	$ -	$ -	$ 53	$ -		**1,563**
63151	51 Resid Energy Stg.	686,351		686,351	$ 30,013	-	$ -	$ -	$ 1,505	$ -		**31,518**
64151	51 Commer Energy Stg.	5,778		5,778	$ 254	-	$ -	$ -	$ 13	$ -		**267**
63152	52 Resid Interruptible	3,217,762		3,217,762	$ 176,634	-	$ -	$ 77	$ 16,313	$ -		**193,024**
64152	52 Commer Interruptible	92,293		92,293	$ 5,076	-	$ -	$ -	$ 471	$ -		**5,547**
63900	Resid-Wellspring *	490,100		490,100	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	11,200		11,200	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	515,900		515,900	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	13,536		13,536	$ 1,527	-	$ -	$ 201	$ 16	$ (12)		**1,732**
64540	54 Time of Use	52,128		52,128	$ 2,601	388	$ 2,704	$ 216	$ 68	$ -		**5,589**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 5,020		**5,020**
64700	70 Full Interruptable	29,178,956		29,178,956	$ 1,457,123	62,536	$ 297,045	$ 25,960	$ 75,847	$ (2,520)	$ -	**1,853,455**
64701	71 Partial Interruptable	2,001,656		2,001,656	$ 100,077	9,462	$ 44,945	$ 2,970	$ 5,204	$ (507)	$ 12,480	**165,170**
63181	81 Cycled Air Resid*	8,877		8,877	$ (284)	$ -	$ -	$ -	$ -	$ -		**(284)**
63182	82&84 Cycled Air UM	-		-	$ (7,192)	-	$ -	$ -	$ -	$ -		**(7,192)**
	Total*	**133,493,022**	**245,202**	**133,247,820**	**$ 11,692,706**	**183,362**	**$ 1,349,961**	**$ 1,089,397**	**$ 221,114**	**$ (10,133)**	**$ 12,480**	**14,355,525**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

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Dakota Electric Association

SALES BY RATE (Billed)

December, 2018

(Accounting Month information downloaded from UMAX)

		kWh				KW						
Account	Rate	Usage	DEA Own Use	kWh NET	Revenue Adjusted	KW	Revenue	Fixed Charges	RTA	Revenue Adjustments	Coincindental Demand	**TOTAL REVENUE per Download**
63100	31 Residential	67,712,680		67,712,680	$ 7,910,573	-	$ -	$ 895,351	$ 81,252	$ (5,749)		**8,881,426**
63200	32 Resl Dem Ctrl	46,724		46,724	$ 3,553	116	$ 1,284	$ 186	$ 56	$ -		**5,079**
63133	33 Resid Electric Vehicles	49,740		49,740	$ 3,761	-	$ -	$ -	$ 60	$ -		**3,821**
63036	36 Irrigation	1,809		1,809	$ 90	8	$ 164	$ 270	$ 2	$ -		**526**
63037	37 Irrigation	23,492		23,492	$ 1,177	715	$ 3,254	$ 11,479	$ 64	$ -		**15,974**
64100	41 Sm Genl Serv	3,671,674	3,578	3,668,096	$ 413,644	-	$ -	$ 62,597	$ 4,395	$ (96)		**480,540**
62440	44 Security Lights	35,711		35,711	$ 8,151	-	$ -	$ -	$ 58	$ -		**8,208**
62441	44-1 Street Lights	43,128		43,128	$ 5,705	-	$ -	$ -	$ 73	$ -		**5,778**
62442	44-2 Street Lights	206,392		206,392	$ 38,131	-	$ -	$ -	$ 351	$ -		**38,481**
62443	44-3 Street Lights	618,332		618,332	$ 109,691	-	$ -	$ -	$ 1,051	$ -		**110,742**
62444	44 Security Lgts - LED	5,891		5,891	$ 2,816	-	$ -	$ -	$ 11	$ -		**2,827**
62445	44-5 Street Lgts - LED	726		726	$ 106	-	$ -	$ -	$ 1	$ -		**107**
62446	44 Street Lgts - LED	18,230		18,230	$ 5,493	-	$ -	$ -	$ 31	$ -		**5,524**
64500	45 Emergency Unmet.	-		-	$ 660	-	$ -	$ -	$ -	$ -		**660**
64600	46 General Service	34,156,287	242,304	33,913,983	$ 2,462,115	105,130	$ 962,990	$ 91,646	$ 44,089	$ (6,557)		**3,554,283**
63047	47 Municipal	-		-	$ 330	-	$ -	$ -	$ -	$ -		**330**
64690	49 Geotherm Heat Pump	20,888		20,888	$ 1,963	-	$ -	$ -	$ 69	$ -		**2,032**
63151	51 Resid Energy Stg.	934,425		934,425	$ 41,116	-	$ -	$ -	$ 2,056	$ -		**43,172**
64151	51 Commer Energy Stg.	12,508		12,508	$ 550	-	$ -	$ -	$ 28	$ -		**578**
63152	52 Resid Interruptible	4,316,386		4,316,386	$ 237,406	-	$ -	$ 65	$ 21,993	$ -		**259,465**
64152	52 Commer Interruptible	125,469		125,469	$ 6,901	-	$ -	$ -	$ 640	$ -		**7,541**
63900	Resid-Wellspring *	476,200		476,200	$ -	-	$ -	$ -	$ -	$ -		**-**
63901	Resid-Wellspring Solar*	11,500		11,500	$ -	-	$ -	$ -	$ -	$ -		**-**
64900	Comm-Wellspring *	540,800		540,800	$ -	-	$ -	$ -	$ -	$ -		**-**
64901	Comm-Wellspring Solar*	2,500		2,500	$ -	-	$ -	$ -	$ -	$ -		**-**
63530	53 Time of Day	19,274		19,274	$ 2,143	-	$ -	$ 238	$ 23	$ (12)		**2,392**
64540	54 Time of Use	54,528		54,528	$ 2,721	390	$ 3,097	$ 216	$ 71	$ -		**6,105**
64660	60 Standby Service	2,000		2,000	$ -	-	$ -	$ -	$ -	$ 5,750		**5,750**
64700	70 Full Interruptable	29,821,368		29,821,368	$ 1,489,166	59,951	$ 284,770	$ 25,850	$ 77,514	$ (2,576)	$ -	**1,874,724**
64701	71 Partial Interruptable	1,777,448		1,777,448	$ 88,889	6,089	$ 28,921	$ 2,970	$ 4,621	$ (510)	$ 5,190	**130,082**
63181	81 Cycled Air Resid*	1,190		1,190	$ (38)	$ -	$ -	$ -	$ -	$ -		**(38)**
63182	82&84 Cycled Air UM	-		-	$ (16,800)	-	$ -	$ -	$ -	$ -		**(16,800)**
	Total*	**143,673,110**	**245,882**	**143,427,228**	**$ 12,820,013**	**172,399**	**$ 1,284,478**	**$ 1,090,868**	**$ 238,508**	**$ (9,749)**	**$ 5,190**	**15,429,308**

*Note: kWh Sales total does not foot since rates 81, 60 and Wellspring are also included in the base rates and therefore excluded from the total

Workpaper 11
Individual Member Actual 2018
Usage and Demand by Rate Class

Rate 31 Residential & Farm Service
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	78,269,908	69,335,675	56,649,523	63,041,013	56,192,721	77,904,757	92,663,962	95,569,046	84,031,403	67,744,229	58,638,849	67,712,680	867,753,766
$	$ 10,119,130.22	$ 9,066,260.18	$ 7,555,692.60	$ 8,311,541.70	$ 7,525,190.20	$ 10,446,297.22	$ 13,109,975.68	$ 13,502,405.35	$ 11,629,096.94	$ 8,901,932.56	$ 7,810,714.96	$ 8,881,425.97	$ 116,859,663.58

Premises	98,623	98,611	98,670	98,820	98,973	98,892	99,053	98,916	99,010	99,262	99,354	99,538

Rate 32 Residential Demand Control
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	117.80	116.84	83.06	78.59	67.00	68.97	61.37	66.13	68.41	65.56	79.76	115.67	989.16
kWh	67,701	61,474	42,954	43,930	29,499	16,121	18,834	16,626	17,694	19,656	26,390	46,724	407,603
$	$ 6,714.08	$ 6,222.70	$ 4,417.64	$ 4,446.16	$ 3,203.40	$ 2,270.93	$ 2,535.16	$ 2,438.04	$ 2,466.63	$ 2,454.18	$ 3,105.02	$ 5,079.02	$ 45,352.96

Premises	15	15	15	15	15	15	15	15	14	15	15	15

Summer kW 196.47

Rate 36 Firm Irrigation
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	1.26	0.27	0.13	40.53	464.10	557.11	558.37	558.35	548.20	431.71	295.90	8.02	3,463.95
kWh	425	382	408	533	45,452	47,841	72,733	72,614	40,248	15,257	3,796	1,809	301,498
$	$ 288.16	$ 265.21	$ 263.23	$ 895.72	$ 9,810.03	$ 16,516.03	$ 18,706.98	$ 18,685.52	$ 11,885.81	$ 7,742.70	$ 5,050.80	$ 526.17	$ 90,636.36

Premises	8	8	8	8	9	9	9	9	9	9	9	9

Summer kW	1,673.83
Winter kW	9.55
Other kW	1,780.57
Sum of Max Demands	568.30

Rate 36 Interruptible Irrigation
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	12.11	15.95	34.29	344.56	7,603.78	14,374.92	22,111.83	22,686.20	9,806.00	1,343.98	2,886.42	715.16	81,935.20
kWh	7,772	7,240	6,918	8,542	249,365	614,953	3,100,117	4,173,975	241,132	39,209	113,248	23,492	8,585,963
$	$ 11,940.57	$ 11,913.88	$ 11,985.35	$ 13,448.47	$ 59,165.58	$ 109,214.29	$ 275,172.88	$ 334,293.58	$ 68,794.43	$ 19,692.95	$ 30,597.95	$ 15,973.55	$ 962,193.48

Premises	383	382	382	381	382	382	383	383	382	381	377	382

Summer kW	59,172.95
Winter kW	743.22
Other kW	22,019.03
Sum of Max Demands	26,154.08

Rate 41 Small General Service
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	4,333,811	3,979,286	3,464,212	3,598,039	3,025,934	3,432,398	3,651,111	3,475,547	3,574,793	3,027,364	3,422,352	3,668,096	42,652,944
$	$ 553,895.24	$ 513,636.07	$ 456,218.63	$ 471,421.12	$ 408,081.95	$ 479,325.51	$ 529,552.70	$ 507,005.43	$ 492,019.78	$ 407,658.46	$ 445,316.35	$ 480,540.35	$ 5,744,671.59

Premises	4,392	4,383	4,373	4,340	4,397	4,374	4,411	4,411	4,420	4,423	4,407	4,439

Rate 46 General Service
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	107,845.55	103,035.88	99,294.82	99,129.14	131,695.07	136,324.35	135,162.79	131,358.63	134,008.75	114,454.41	107,714.10	105,129.90	1,405,153.39
First 200 kWh	20,478,815	19,693,334	18,904,791	18,850,915	22,014,483	24,684,234	24,662,027	24,109,370	24,439,671	20,514,614	19,700,147	19,473,431	257,525,832
Next 200 kWh	13,998,237	12,963,993	12,002,000	12,558,268	10,411,187	14,165,570	15,101,214	14,625,692	15,041,454	10,481,731	11,891,948	11,579,771	154,821,065
Over 400 kWh	4,976,498	2,994,119	2,941,256	3,264,944	1,867,057	2,946,554	3,601,430	3,372,491	3,409,133	2,163,590	3,217,360	2,860,781	37,615,213
Total kWh	39,453,550	35,651,446	33,848,047	34,674,127	34,292,727	41,796,358	43,364,671	42,107,553	42,890,258	33,159,935	34,809,455	33,913,983	449,962,110
$	$ 3,951,109.46	$ 3,657,765.67	$ 3,492,803.08	$ 3,549,971.73	$ 3,777,261.00	$ 4,704,370.04	$ 4,940,892.42	$ 4,785,405.98	$ 4,611,317.50	$ 3,600,303.80	$ 3,629,808.73	$ 3,554,282.93	$ 48,255,292.34

Premises	2,716	2,675	2,689	2,687	2,668	2,688	2,682	2,687	2,688	2,687	2,679	2,683

Summer kW 402,845.77

Sum of Max Demands 177,923.08

Rate 51 Controlled Energy Storage
2018 Actual Billed

Total 51

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	1,106,238	1,070,776	842,619	1,011,158	768,093	881,191	1,006,265	977,219	867,728	683,089	692,129	946,933	10,853,438
$	$ 51,102.04	$ 49,466.93	$ 38,930.50	$ 46,673.05	$ 35,486.83	$ 40,712.06	$ 46,490.80	$ 45,148.67	$ 40,090.97	$ 31,560.20	$ 31,785.21	$ 43,749.59	$ 501,196.85

Premises	1,617	1,610	1,605	1,611	1,632	1,639	1,625	1,634	1,636	1,667	1,655	1,683

Residential 31 51

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	1,091,315	1,056,827	833,258	1,002,160	761,089	874,403	999,795	970,127	862,054	678,919	686,351	934,425	10,750,723
$	$ 50,412.62	$ 48,822.48	$ 38,498.05	$ 46,257.34	$ 35,163.25	$ 40,398.40	$ 46,191.88	$ 44,821.01	$ 39,828.84	$ 31,367.53	$ 31,518.27	$ 43,171.71	$ 496,451.38

Premises	1,602	1,595	1,590	1,595	1,617	1,625	1,612	1,620	1,624	1,655	1,640	1,668

Small General Service 41 51

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	7,910	7,324	4,303	4,461	3,048	2,566	2,233	2,439	2,239	2,313	3,508	6,201	48,545
$	$ 365.42	$ 338.38	$ 198.78	$ 206.09	$ 140.82	$ 118.60	$ 103.17	$ 112.70	$ 103.44	$ 106.87	$ 162.07	$ 286.49	$ 2,242.83

Premises	11	11	11	12	11	10	9	10	8	8	11	11

General Service 46 51

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	7,013	6,625	5,058	4,537	3,956	4,222	4,237	4,653	3,435	1,857	2,270	6,307	54,170
$	$ 324.00	$ 306.07	$ 233.67	$ 209.62	$ 182.76	$ 195.06	$ 195.75	$ 214.96	$ 158.69	$ 85.80	$ 104.87	$ 291.39	$ 2,502.64

Premises	4	4	4	4	4	4	4	4	4	4	4	4

Rate 52 Controlled Interruptible Service
2018 Actual Billed

Total 52

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	5,562,145	5,287,263	4,185,976	4,547,171	3,287,312	3,581,170	4,200,405	4,118,692	3,624,688	2,932,905	3,310,055	4,441,855	49,079,637
$	$ 334,198.79	$ 317,687.01	$ 251,555.67	$ 273,279.51	$ 197,553.07	$ 215,218.50	$ 252,436.80	$ 247,528.62	$ 217,874.90	$ 176,269.90	$ 198,570.70	$ 267,005.54	$ 2,949,179.01

Premises	6,519	6,474	6,473	6,470	6,640	6,855	6,852	6,838	6,832	6,820	6,518	6,542

Residential 31 52

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	5,387,021	5,121,189	4,066,783	4,424,731	3,214,010	3,502,913	4,119,863	4,041,975	3,561,537	2,880,182	3,217,762	4,316,386	47,854,352
$	$ 323,702.10	$ 307,725.27	$ 244,392.09	$ 265,920.75	$ 193,147.46	$ 210,515.16	$ 247,596.14	$ 242,917.89	$ 214,079.45	$ 173,101.16	$ 193,023.75	$ 259,464.73	$ 2,875,585.95

Premises	6,437	6,395	6,392	6,391	6,562	6,781	6,782	6,769	6,761	6,746	6,439	6,458

Small General Service 41 52

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	80,826	83,544	55,591	60,482	34,859	21,664	17,437	18,026	13,669	14,963	40,115	61,088	502,264
$	$ 4,829.36	$ 5,001.67	$ 3,341.10	$ 3,635.04	$ 2,095.13	$ 1,302.10	$ 1,048.01	$ 1,083.38	$ 821.55	$ 899.33	$ 2,411.00	$ 3,671.46	$ 30,139.13

Premises	45	44	46	44	42	40	35	34	37	38	44	48

General Service 46 52

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh	94,298	82,530	63,602	61,958	38,443	56,593	63,105	58,691	49,482	37,760	52,178	64,381	723,021
$	$ 5,667.33	$ 4,960.07	$ 3,822.48	$ 3,723.72	$ 2,310.48	$ 3,401.24	$ 3,792.65	$ 3,527.35	$ 2,973.90	$ 2,269.41	$ 3,135.95	$ 3,869.35	$ 43,453.93

Premises	37	35	35	35	36	34	35	35	34	36	35	36

Rate 53 Time of Day
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
On Peak Kwh	5,459	5,243	4,410	4,214	3,121	4,061	4,523	4,192	3,790	2,963	3,148	4,109	49,233
Off Peak kWh	19,948	15,840	17,426	16,400	10,820	12,284	13,431	12,544	12,318	10,251	10,388	15,170	166,820
$	$ 3,059.48	$ 2,633.45	$ 2,635.58	$ 2,505.98	$ 1,783.25	$ 2,120.44	$ 2,339.58	$ 2,190.91	$ 2,075.10	$ 1,689.94	$ 1,731.66	$ 2,392.07	$ 27,157.44

Premises	18	18	18	18	18	18	18	18	18	17	17	18

Summer on Peak kWh	12,776
Other on Peak kWh	36,457

Rate 54 General Service Time of Use
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Max kW	199.20	323.04	312.48	277.92	458.40	449.76	449.28	637.92	521.28	280.80	284.16	285.60	4,479.84
Peak kW	183.88	183.36	265.92	262.56	258.72	346.56	346.08	343.20	360.48	100.32	104.16	104.16	2,859.40
On Peak kWh	4,416	3,984	6,576	8,784	2,592	5,904	6,144	7,872	3,120	2,256	2,640	3,600	57,888
Off Peak kWh	57,024	68,160	76,368	85,056	70,848	135,840	157,488	149,424	131,040	53,904	49,488	50,928	1,085,568
Total $	$ 7,773.49	$ 8,918.88	$ 9,840.48	$ 9,753.99	$ 9,516.88	$ 16,764.49	$ 19,328.14	$ 19,828.19	$ 15,520.81	$ 5,729.37	$ 5,588.79	$ 6,104.53	$ 134,668.04

Premises	6	6	6	6	6	6	6	6	6	6	6	6

Summer Peak kW	1,035.84
Winter Peak kW	471.40
Other Peak kW	1,352.16

Rate 70 Full Interruptible Service
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	63,341.97	63,657.26	58,301.06	69,103.30	85,088.58	84,703.88	85,002.61	83,259.35	83,037.40	72,629.45	62,535.75	59,951.47	870,612.08
Coinc kW	-	-	-	-	-	-	1,042.80	-	-	-	-	-	1,042.80
kWh	30,622,046	27,669,400	29,653,518	28,846,311	34,741,023	35,173,960	37,349,811	37,670,413	33,196,188	30,335,042	29,178,956	29,821,368	384,258,036
$	$ 1,931,610.46	$ 1,778,454.68	$ 1,857,985.15	$ 1,866,737.49	$ 2,251,492.54	$ 2,272,554.84	$ 2,428,513.23	$ 2,396,775.88	$ 2,161,295.08	$ 1,961,963.57	$ 1,853,820.12	$ 1,875,161.46	$ 24,636,364.50

Premises	231	231	231	231	229	231	233	233	234	233	235	235

Coincident kW	
Summer	1,042.80
Winter	-
Other	-
Sum of Max Demands	97,822.10

Rate 71 Partial Interruptible Service
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed kW	5,302.11	5,331.97	4,946.42	7,609.86	10,444.42	10,899.97	10,314.63	10,505.48	11,230.77	10,654.56	9,462.17	6,088.63	102,790.99
Coinc kW	834.45	987.69	808.08	764.83	819.90	619.77	1,235.73	1,102.86	1,095.87	1,015.24	989.05	922.54	11,196.01
Excess kW	-	-	-	-	-	-	5.45	-	-	-	-	-	5.45
kWh	1,775,480	1,639,288	1,719,928	1,928,576	2,519,360	2,389,864	2,444,376	2,528,544	2,408,936	2,396,088	2,001,656	1,777,448	25,529,544
$	$ 136,713.35	$ 132,645.81	$ 126,890.94	$ 150,019.74	$ 195,034.26	$ 194,061.80	$ 209,258.79	$ 211,287.31	$ 208,361.29	$ 203,163.92	$ 165,170.02	$ 130,081.60	$ 2,062,688.83

Premises	26	26	26	27	27	27	27	27	27	27	27	26

Coincidental kW	
Summer	2,958.36
Winter	2,744.68
Other	5,492.97
Sum of Max Demands	12,911.63

Rate 81 Cycled Air Conditioning
2018 Actual Billed

Item	January	February	March	April	May	June	July	August	September	October	November	December	Total
Total Rate 81													
Off Peak kWh	122	303	3,458	777	213,468	863,749	1,336,411	1,324,027	1,062,795	370,025	8,877	1,190	5,185,202
$	$ (8.45)	$ (4.83)	$ (110.66)	$ (24.87)	$ (6,830.97)	$ (27,639.86)	$ (42,765.39)	$ (42,368.80)	$ (34,009.28)	$ (11,840.85)	$ (284.09)	$ (38.08)	$ (165,926.13)
Premises						3,508	3,536	3,522	3,511				
Rate 81 Residential													
Off Peak kWh	122	303	3,232	777	149,135	804,868	1,269,260	1,257,710	1,007,575	351,034	8,836	990	4,853,842
$	$ (8.45)	$ (4.83)	$ (103.43)	$ (24.87)	$ (4,772.31)	$ (25,755.66)	$ (40,616.57)	$ (40,246.64)	$ (32,242.24)	$ (11,233.14)	$ (282.78)	$ (31.68)	$ (155,322.60)
Premises						3,477	3,505	3,491	3,480				
Rate 81 Commercial													
Off Peak kWh	-	-	226	-	64,333	58,881	67,151	66,317	55,220	18,991	41	200	331,360
$	$ -	$ -	$ (7.23)	$ -	$ (2,058.66)	$ (1,884.20)	$ (2,148.82)	$ (2,122.16)	$ (1,767.04)	$ (607.71)	$ (1.31)	$ (6.40)	$ (10,603.53)
Premises						31	31	31	31				

Workpaper 10
Estimate of System Losses and System Own Use

Dakota Electric Association
System Line Loss
Five-Year Average

(A)	(B)	(C)	(D)	(E)	(F)
Year	kWh Purchased	kWh Sold	kWh Own Use	kWh Loss*	Line Loss % of Purchases
2014	1,887,361,641	1,828,435,319	2,305,477	56,620,845	3.000%
2015	1,849,855,685	1,792,314,743	2,045,275	55,495,668	3.000%
2016	1,872,717,331	1,821,974,126	2,052,552	48,690,653	2.600%
2017	1,840,403,827	1,820,488,783	2,064,546	17,850,498	0.970%
2018	1,901,355,817	1,851,702,114	2,119,811	47,533,892	2.500%
Total	9,351,694,301	9,114,915,085	10,587,661	226,191,556	2.420%

* 2016 reflects the impact of a reduction in line loss % from 3.0% to 2.6% based on a system-wide line loss analysis
* 2017 kWh sold includes a 30 million kWh impact for an unbilled/line loss true-up. Line loss % of purchases is 2.6% excluding the true-up
* 2018 reflects the impact of a reduction in line loss % from 2.6% to 2.5% based on a system-wide line loss analysis

Source of Data & Computations

(B)	CFC Form 7, Part R, Line 16: 12/31
(C)	CFC Form 7, Part R, Line 11: 12/31
(D)	CFC Form 7, Part R, Line 15: 12/31
(E)	(B) - (C) - (D)
(F)	(E) / (B)

Workpaper 9
Conservation Improvement Program

Dakota Electric Association
Conservation Improvement Program Filing Summary

Dakota Electric CIP information is included in the consolidated GRE conservation report, most recently submitted to the Minnesota Department of Commerce in June 2019. Dakota Electric submits our Annual Conservation Tracker information to the MPUC as part of our Resource and Tax Adjustment mechanism.

A schedule detailing the 2019 budget of $2,206,787 is included. In addition, a schedule showing the 2018 actual conservation and DSM expenditures of $2,407,082 and the 2018 year-end tracker balance is also enclosed.

Dakota Electric Association
2019 Conservation Improvement Program

Project Name	Description	2019 Budget
ACTUNEUP	Air Conditioning Tune-Up Proj	2,138
AUDC	Energy Audits Commercial & Ind	8,691
AUDLOW	Low Income Audit Program	938
AUDR	Energy Audits Residential	20,858
CACCI	Cycled Air - Comml & Ind	4,232
CACRES	Cycled Air - Residential	55,824
CIGRANT	C&I Energy Grant	566,912
CIGROUP	C&I Energy Group	16,000
CIPDIGITAL	Digital Advertising-Energy Efficiency/Conserv	36,600
CIPGOALS	CIP Goals	118,893
CIPNEWS	Newspaper Advert-Energy Efficiency	11,000
CIPTV	TV Advertising-Energy Efficiency	85,740
CIRC	Circuits	425,148
DEHUMID	Dehumidifier Rebate	1,163
E3TRAIN	Energy Effic Training & Educatation	18,274
ECMMOTOR	ECM Rebate Program	7,350
EIL	Energy Intelligent Lifestyle	43,306
EILPROD	Energy Intel Lifestyle-Product	34,670
ELECCAR	Electric Car	64,090
ELECHEAT	Electric Heat	18,461
ESDRYER	Energy Star Clothes Dryer	338
FAIRSHOW	Fairs & Shows	20,335
FRECYCLE	Fluorescent Lamp Recycling	15,438
FREEZER	Energy Star - Freezer	900
GENMT	Generator Maint & Testing	29,940
GPUMPRES	Geothermal Heat Pump Residential	1,417
HIEFF	High Efficiency A/C Rebates	252,408
HPUMP	Heat Pumps - Residential	23,454
HPWH	Heat Pump Water Heater	-
INCELIGIBL	Income Eligible Non Cap Projects	1,125
IRRIG	Interruptible Irrigation	23,093
LEDLIGHTS	LED - Lights	23,650
LEDYARD	LED Yard Light	-
LIACMAINT	Low Income A/C Tune-up	-
LIAIRCON	Low Income Central Air Conditioner Replace	-
LICLSWSHR	Low Income Clothes Washer	-
LIDEHUMID	Low Income Dehumidifier Units	-
LIDISH	Low Income Dishwashers	-
LIFREEZER	Low Income Freezers	-
LIMICRO	Low Income Microwave Ovens	-
LIROOMAC	Low Income Room Air Conditioner	-
LIWTRHTR	Low Income Water Heater	-
LOADCTRL	Load Control	103,463
NCEEP	New Construction Energy Efficient Program	5,700
PEAK	Peak Alert Rate 70	8,866
PLCMASTER	Power Line Carrier Master	45,456
POOLHEAT	Heat Pump Pool Heater	-
POOLPUMP	Pool Pump Variable Speed Motor	150
REFRIGLOW	Low Income Refrig Replacement	1,350
REGD	Regulatory - DSM	141,320
RENEW	Optional Renewable Energy	3,875
RFGRCYC	Refrigerator Recycling	3,675
ROOMSTORG	Room storage-electric heat	4,998
SOLAR	Solar Electric General Activity & Education	69,500
WARFZ	Working Appliance Recyc Freeze	360
WARRF	Working Appliance Recycling Refrigerator	638
WTRHTR	Water Heaters	66,019
DSM	DSM Depreciation	118,212
TOTAL		$ 2,505,968
	Less 70% of CIRC as non-CIP	(297,604)
	Less RENEW Labor & Payroll OH	(1,575)
TOTAL CIP		**$ 2,206,789**

Dakota Electric Association
DSM/Conservation Tracker Account
Year Ended December 31, 2018

A	B	C	D	E	F	G
	Conservation Account # 16120	Carrying Cost @	Resource	Additions	Conservation Expenses	
Month	Balance	6.52%	Adjustment Recovery	to Tracker Account	Expenses Incurred	Recovery in Base Rates
Dec-17	959,145.50					
Jan-18	901,002.41	5,211.00	(81,175.77)	17,821.68	212,643.52	(194,821.84)
Feb-18	776,499.93	4,895.00	(72,865.13)	(56,532.35)	118,343.96	(174,876.31)
Mar-18	712,357.35	4,219.00	(65,741.35)	(2,620.23)	155,159.02	(157,779.25)
Apr-18	610,062.21	3,870.00	(69,392.95)	(36,772.19)	129,770.89	(166,543.08)
May-18	552,507.17	3,315.00	(68,065.99)	7,195.95	170,554.34	(163,358.39)
Jun-18	448,798.77	3,002.00	(83,515.63)	(23,194.77)	177,242.74	(200,437.51)
Jul-18	253,389.00	2,438.00	(94,508.73)	(103,339.04)	123,481.91	(226,820.95)
Aug-18	113,724.11	1,377.00	(95,925.22)	(45,116.67)	185,103.86	(230,220.53)
Sep-18	56,045.48	618.00	(86,005.36)	27,708.73	234,121.59	(206,412.86)
Oct-18	13,847.34	305.00	(70,698.22)	28,195.08	197,870.80	(169,675.72)
Nov-18	161,724.13	75.00	(66,623.91)	214,425.70	374,323.08	(159,897.38)
Dec-18	247,243.44	879.00	(71,713.61)	156,353.92	328,466.59	(172,112.67)
Annual Total	(711,902.06)	30,204.00	(926,231.87)	184,125.81	2,407,082.30	(2,222,956.49)

Workpaper 8
Depreciation Summary

Dakota Electric Association
Depreciation Summary

Dakota Electric's most recent 5-year depreciation study was filed June 2017 in Docket No. E111/D-17-505. The current annual depreciation rates by plant account are detailed on the enclosed summary schedule from this filing.

Dakota Electric Association
Annual Depreciation
Year 2017
Schedule A 2017

Account Number	Description	Gross Plant 1/1/2017	50% of Estimated 2017 Addition	50% of Estimated 2017 Retirement	Average Balance 2017	PRESENT Average or Weighted Service Life (Yrs)	PRESENT Net Salvage Percent	PRESENT Accrual Rate or Weighted Average Accrual Rate	PRESENT Annual Accrual	PROPOSED Average or Weighted Service Life (Yrs)	PROPOSED Net Salvage Percent	PROPOSED Accrual Rate or Weighted Average Accrual Rate	PROPOSED Annual Accrual	Proposed Increase (Decrease)
Distribution Plant														
36000	Land and Land Rights	4,004,579	19,285	-	4,023,863	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36200	Station Equipment	28,927,702	1,150,000	(23,315)	30,054,387	37.00	0.00%	2.70%	811,468	37.00	0.00%	2.70%	811,468	-
36250	Station Equipment - DSM	3,931,509	-	-	3,931,509	11.00	0.00%	9.09%	-	11.00	0.00%	9.09%	-	-
36255	Station Equipment - DSM Post 2008	767,103	248,000	-	1,015,103	11.00	0.00%	9.09%	92,273	11.00	0.00%	9.09%	92,273	-
36260	Station Equipment - Comm	760,766	-	(37,800)	722,966	6.00	0.00%	16.67%	-	6.00	0.00%	16.67%	-	-
36265	Station Equipment - Comm Post 2009	577,894	315,000	-	892,894	6.00	0.00%	16.67%	148,845	6.00	0.00%	16.67%	148,845	-
36400	Poles, Towers and Fixtures	18,370,537	342,418	(102,258)	18,610,697	29.00	-5.00%	3.62%	673,707	29.00	-5.00%	3.62%	673,707	-
36500	Overhead Conductors and Devices	20,033,477	322,469	(109,313)	20,246,633	30.00	2.00%	3.27%	662,065	30.00	2.00%	3.27%	662,065	-
36700	Underground Conductors and Devices	117,131,608	1,673,273	(699,112)	118,105,769	33.00	5.00%	2.88%	3,401,446	33.00	5.00%	2.88%	3,401,446	-
36800	Line Transformers	38,540,620	699,637	(298,561)	38,941,696	29.00	10.00%	3.10%	1,207,193	29.00	10.00%	3.10%	1,207,193	-
36900	Services	3,309,321	34,666	(1,310)	3,342,678	35.00	-20.00%	3.43%	114,654	35.00	-20.00%	3.43%	114,654	-
37000	Meters	6,866,992	62,309	(39,276)	6,890,025	**25.00**	**0.00%**	**4.00%**	**275,601**	**15.00**	**0.00%**	**6.67%**	**459,565**	183,964
37020	Meters - Used	85,400	-	-	85,400	**15.00**	**0.00%**	**6.67%**	**5,696**	**5.00**	**0.00%**	**20.00%**	**17,080**	11,384
37050	Load Control Meters - DSM	633,490	-	-	633,490	**25.00**	**0.00%**	**4.00%**	**25,340**	**15.00**	**0.00%**	**6.67%**	**42,254**	16,914
37100	Installations on Customers' Premises	233,244	1,352	(24,769)	209,827	**20.00**	**-7.00%**	**5.35%**	**11,226**	**20.00**	**-10.00%**	**5.50%**	**11,540**	314
37120	Installations on Customers' Premises - LED*	121,704	61,512	(660)	182,556	**-**	**0.00%**	**0.00%**	**-**	**16.00**	**0.00%**	**6.25%**	**11,410**	11,410
37150	Load Control Receivers - DSM	228,463	-	(1,606)	226,858	12.00	0.00%	8.33%	-	12.00	0.00%	8.33%	-	-
37300	Street Lighting and Signal Systems	7,717,703	306,121	(54,636)	7,969,187	**22.00**	**10.00%**	**4.09%**	**325,940**	**22.00**	**-5.00%**	**4.77%**	**380,130**	54,190
37320	Street Lighting and Signal Systems - LED*	38,326	19,163	-	57,490	**-**	**0.00%**	**0.00%**	**-**	**16.00**	**0.00%**	**6.25%**	**3,593**	3,593
	TOTAL	252,280,440	5,255,205	(1,392,616)	256,143,028	32.51		3.08%	7,755,454	31.37		3.19%	8,037,223	281,769
General Plant														
38900	Land and Land Rights	102,278	-	-	102,278	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
39000	Structure and Improvements	7,821,782	121,158	(7,770)	7,935,170	**37.50**	**12.50%**	**2.33%**	**184,889**	**34.50**	**12.50%**	**2.54%**	**201,553**	16,664
39050	Security Equipment	316,269	7,006	(39,059)	284,216	6.00	0.00%	16.67%	47,379	6.00	0.00%	16.67%	47,379	-
39100	Office Furniture and Equipment	1,104,287	2,081	(69,838)	1,036,529	12.00	0.00%	8.33%	86,343	12.00	0.00%	8.33%	86,343	-
39110	Computer Equipment	4,940,452	84,017	(16,362)	5,008,107	**5.40**	**0.00%**	**14.69%**	**725,916**	**5.00**	**0.00%**	**16.33%**	**806,573**	80,657
39120	Computer Equipment - DSM	1,432,598	-	-	1,432,598	6.00	0.00%	16.67%	238,814	6.00	0.00%	16.67%	238,814	-
39130	Computer Equipment - Leased	426,168	151,675	(210,890)	366,953	4.00	0.00%	25.00%	91,738	4.00	0.00%	25.00%	91,738	-
39200	Autos & Small Trucks	1,943,593	80,768	(106,269)	1,918,093	7.00	10.00%	10.58%	205,544	7.00	10.00%	10.58%	205,544	-
39300	Stores Equipment	52,570	2,118	(133)	54,554	15.00	0.00%	6.67%	3,639	15.00	0.00%	6.67%	3,639	-
39400	Tools and Line Equipment	818,627	5,021	(115,248)	708,399	16.00	0.00%	6.25%	44,275	16.00	0.00%	6.25%	44,275	-
39410	Shop and Garage Equipment	167,264	7,936	(15,054)	160,146	20.00	0.00%	5.00%	8,007	20.00	0.00%	5.00%	8,007	-
39450	Tools and Related Line Equipment - DSM	-	-	-	-	16.00	0.00%	6.25%	-	16.00	0.00%	6.25%	-	-
39500	Laboratory Equipment	319,265	50,020	(6,278)	363,008	**20.00**	**0.00%**	**5.00%**	**18,150**	**15.00**	**0.00%**	**6.67%**	**24,213**	6,063
39510	Hand Held Meter Reading Devices	98,598	3,080	(11,316)	90,362	6.00	0.00%	16.67%	15,063	6.00	0.00%	16.67%	15,063	-
39620	Power Operated Equipment	1,028,226	(3,767)	-	1,024,459	12.00	5.00%	6.86%	70,278	12.00	5.00%	6.86%	70,278	-
39630	Heavy Transportation Equipment	4,561,863	116,955	(182,830)	4,495,988	**14.22**	**9.54%**	**4.71%**	**214,994**	**11.80**	**9.54%**	**4.85%**	**221,362**	6,368
39700	Communication Equipment	774,886	93,349	(15,040)	853,195	7.50	0.00%	13.33%	113,731	7.50	0.00%	13.33%	113,731	-
39710	Base Stations and Tower	137,908	-	-	137,908	20.00	0.00%	5.00%	6,895	20.00	0.00%	5.00%	6,895	-
39800	Miscellaneous Equipment	260,521	22,155	(7,869)	274,807	9.00	0.00%	11.11%	30,531	9.00	0.00%	11.11%	30,531	-
	TOTAL	26,307,156	743,571	(803,957)	26,246,770	12.41		8.06%	2,106,186	11.80		8.48%	2,215,938	109,752
39999	General Plant Work in Process	2,393,925												
	TOTAL ELECTRIC PLANT IN SERVICE	278,587,595	5,998,776	(2,196,574)	282,389,798	28.22		3.54%	9,861,640	27.14		3.68%	10,253,161	391,521

***** New account category; split from parent account

Workpaper 7
Cost Allocation Policy

Dakota Electric Association
Cost Allocation Policy

Dakota Electric uses a fully allocated costing approach to assign and allocate costs between regulated and non-regulated activities which follows the cost allocation principles recommended by the Public Utilities Commission in Docket No. G, E999/CI-90-1008. Enclosed is a copy of Dakota Electric's November 1994 Compliance Report. The Cooperative continues to adhere to the hierarchical principles adopted by the Commission in 1994.

Since our rate filing in 2009, Dakota Electric has phased out a large portion of its for-profit subsidiaries. During 2011, Midwest Energy Services (MES) sold all of its shares of stock in Consulting Engineers Group, Inc. (CEG). During 2012, Energy Alternatives Parent, Inc. (EAI) sold all of its membership interests in its leasing and wholesale generation businesses.

Dakota Electric currently has a for-profit wholly-owned subsidiary holding company, Midwest Energy Services (MES), which owns Energy Alternatives Parent, Inc. (EAI) (formerly named Dakota Energy at the time of the enclosed Compliance Report). EAI owns Energy Alternatives Solar, LLC (EAS). EAS leased customer-sited solar photovoltaic generation. The remaining leases were all terminated in 2019 prior to this rate filing.

The cost allocation system for contracted Dakota Electric services for the subsidiaries are formalized through annual agreements. The subsidiaries books are kept separately and the net income of the consolidated subsidiaries is separately identified in Form 7 (Workpaper 1) on line 24 of the income statement entitled Income (Loss) from Equity Investments.

All revenues and expenses related to Dakota Electric's internal non-regulated activities are tracked in detail using separate project codes. These projects are mapped to FERC accounts 415 and 416 when preparing the annual Form 7 income statement and are therefore captured in line 25 of the Form 7 entitled Non Operating Margins – Other (Workpaper 1). These non-regulated activities currently include sub-contracting services to other utilities and equipment sales to customers.

Workpaper 6
Lead-Lag Study Detail

Dakota Electric Association
Summary of Lead Lag Analysis
Cash Working Capital Analysis
Twelve Months Ending December 31, 2018

Description	Test Year Expense	365 Average Daily Expense	Expense Lag	Revenue Lag		Net Lag/ (Lead)	Working Capital Required/ (Provided)
Purchased Power	$ 149,356,821	$ 409,197	51.7	55.1		3.4	$ 1,399,996
Payroll (A)	15,112,543	41,404	11.0	55.1		44.1	1,826,799
Employee Benefits	6,003,178	16,447	(37.5)	55.1		92.6	1,523,343
Other O&M	9,484,952	25,986	18.3	55.1		36.8	956,839
Prepaid Insurance	570,291	1,562	(180.6)	55.1		235.7	368,197
Employer FICA/Medicare	1,334,808	3,657	14.4	55.1		40.7	148,918
Federal & State Unemployment Tax	26,186	72	60.0	55.1		(4.9)	(351)
Property Taxes	3,432,442	9,404	(30.5)	55.1		85.6	805,183
Total Expenses	$ 185,321,221						$ 7,028,924
Sales Tax	$ 11,767,404	32,239	34.9	28.3	(B)	(6.6)	$ (212,777)
Working Capital Required/ (Provided)							$ 6,816,147

(A) Operating payroll is estimated to be 86% of total payroll
(B) Revenue Collection or Customer Payment Lag

Dakota Electric Association
Lead-Lag Study Notes

Working capital definition
Cash working capital is the amount of investment in addition to net plant and materials and supplies that is necessary to provide safe and quality electric service.

Lead/lag study description
A lead/lag study is an analysis which measures the length of time from providing electric service until payment is received from the customer and the length of time from the receipt of goods or services from the utility's vendors until the utility pays its vendors.

Period of time used to determine the revenue and expense lead/lag days in the study
The revenue and expense days were measured for the 12 months ending December 31, 2018.

Results of the lead/lag study
The lead/lag study resulted in a cash working capital requirement of $6,816,147.

Description of the summary page entitled Dakota Electric Association, Cash Working Capital Analysis, for the twelve months ending December 31, 2018
The summary page sets forth the results of the lead/lag analysis. For each line item of expense, the average expense lead or lag days has been calculated. This number is then subtracted from the revenue lag. The net lead or lag is then multiplied by the average daily expense. The result is the amount of cash working capital provided by or required for that expense.

Revenue lag calculation
The revenue lag was determined by adding together the service period lag, billing lag and collection lag. A service period lag of 15.2 days was calculated by dividing the average number of days in a month by two (30.4/2 = 15.2). This calculation assumes that, on average, the customer receives all of the service for the period for which the meter is read at the midpoint of that period.

A billing lag of 11.6 days was determined by averaging the number of days from each meter reading date to its associated billing date in the 12 month time period.

A collection lag or customer payment lag of 28.3 days was calculated by dividing the sum of the daily accounts receivable balances of the 12 month time period by the sum of billed revenues and sales tax for the same period. The sum of the three lags amounted to a total revenue lag of 55.1 days.

Purchased power
All invoices from Great River Energy were analyzed for purchased power transactions. The lag days were developed from the midpoint in the service period to the date each invoice was paid. From this analysis an average lag of 51.7 days was calculated.

Payroll
The determination of lag days for payroll involved the analysis of both hourly and salary payroll dollars. Separate lags were calculated for net payroll, payroll taxes, contributions to 401K, credit union, investment funds deductions, and union dues withholdings. A weighted average of the lags for net payroll and withholdings was then calculated separately for both hourly and salary payrolls. A second weighted average of 11.0 days was calculated for the two payrolls and assigned to total gross payroll.

Benefits
Benefits were divided into six groups; including disability, 401K contributions, pension, HSA funding, medical/dental premiums, and life insurance. Lags were based on actual payment dates that occurred during the 12 month period, with the largest change occurring in the timing of pension payments. The total average lag was negative 37.5 days.

Other O&M expenses.
A lag of 18.3 days was calculated by analyzing a sample of invoices paid during the 12 month period. This sample included vendors with total payments that were greater than $10,000. A comparison was made between invoice date and payment date and the lag days for O&M expenses are a weighted average of total invoices included in this sample.

Determination of expense lags for remaining expense items on the summary page
The lag of negative 180.6 days assigned to prepaid insurance is a weighted average lag based on actual payment dates. The lag of 14.4 assigned to employer FICA and Medicare is the weighted average of the lags for payroll taxes for hourly and salary payrolls. The lag of 60.0 days assigned to federal and state unemployment taxes is based on payments made on the 15th on the month following the last month of the quarter. The lag of negative 30.5 days assigned to property taxes is a weighted average based on statutory payment due dates for property and real estate taxes.

Determination of the net lead for sales tax and the effect of collecting sales tax on DEA's cash working capital requirement.
The net lead for sales tax of 6.6 days was determined by measuring the number of days from when customers are billed for services provided, until DEA pays the sales tax associated with the billed services, and the number of days it takes DEA to collect the sales tax from customers. An expense lag of 34.9 days was calculated for DEA to pay the sales tax compared to a revenue lag of 28.3 days for DEA to collect it. Therefore, DEA is provided with 6.6 days of working capital related to the collection of sales tax.

Dakota Electric Association

Cash Working Capital Analysis
Determination of Revenue Lag
Twelve Months Ending December 31, 2018

Service Period Lag	15.2	Days	
Billing Lag	11.6		*(Total days billed/total customers billed)*
Payment Lag	28.3		
Total Revenue Lag	55.1	Days	

Determination of Payment Lag

Total Billed for 12 Months	$	227,300,733	
Total of 365 days A/R Balances 12 Months	$	6,443,825,455	
Payment Lag		28.3	Days

Dakota Electric Association

Cash Working Capital Analysis

Determination of Lag for Purchased Power

Twelve Months Ending December 31, 2018

Great River Energy

Service Period				Date	Days	Dollar
Start	Finish	Mid-Point	Amount	Paid	Lag	Days
1-Jan-18	31-Jan-18	16-Jan-18	$ 12,993,995	7-Mar-18	50.0	$ 649,699,750
1-Feb-18	28-Feb-18	14-Feb-18	11,358,844	6-Apr-18	50.5	573,621,622
1-Mar-18	31-Mar-18	16-Mar-18	9,600,693	7-May-18	52.0	499,236,036
1-Apr-18	30-Apr-18	15-Apr-18	9,035,685	7-Jun-18	52.5	474,373,463
1-May-18	31-May-18	16-May-18	11,978,294	6-Jul-18	51.0	610,892,994
1-Jun-18	30-Jun-18	15-Jun-18	17,453,044	7-Aug-18	52.5	916,284,810
1-Jul-18	31-Jul-18	16-Jul-18	18,419,484	7-Sep-18	53.0	976,232,652
1-Aug-18	31-Aug-18	16-Aug-18	18,210,712	5-Oct-18	50.0	910,535,600
1-Sep-18	30-Sep-18	15-Sep-18	12,431,474	7-Nov-18	52.5	652,652,385
1-Oct-18	31-Oct-18	16-Oct-18	8,853,817	7-Dec-18	52.0	460,398,484
1-Nov-18	30-Nov-18	15-Nov-18	9,368,446	7-Jan-19	52.5	491,843,415
1-Dec-18	31-Dec-18	16-Dec-18	9,652,333	7-Feb-19	53.0	511,573,649
Total			$ 149,356,821			$ 7,727,344,860
				Purchase Power Lag Days	51.7	

Dakota Electric Association
Cash Working Capital Analysis
Payroll Summary
Twelve Months Ending December 31, 2018

Combined Salary and Hourly Payroll

Description		Amount	Days Lag		Dollar Days
Salary Payroll	$	8,629,752	7.6	$	65,866,532
Hourly Payroll		8,942,972	14.2		126,829,910
Total - Average Lag	$	17,572,724	11.0	$	192,696,442

Salary Payroll

Description		Amount	Days Lag		Dollar Days
Net Payroll	$	5,410,692	6.0	$	32,464,152
Payroll Taxes		2,284,610	11.0		25,130,710
401K		899,855	9.0		8,098,695
Homestead		34,595	5.0		172,975
Subtotal - Average Lag	$	8,629,752	7.6		65,866,532
Other	$	895,371	N/A		
Total	$	9,525,123			

Hourly Payroll

Description		Amount	Days Lag		Dollar Days
Net Payroll	$	5,692,489	13.0	$	74,002,357
Payroll Taxes		2,159,652	18.0		38,873,736
401K		908,619	13.0		11,812,047
Homestead		75,662	10.0		756,620
Union Dues		106,550	13.0		1,385,150
Subtotal - Average Lag	$	8,942,972	14.2	$	126,829,910
Other	$	815,191	N/A		
Total	$	9,758,163			

Dakota Electric Association

Cash Working Capital Analysis

Determination of Lag for Employee Benefits

Twelve Months Ending December 31, 2018

Description	Amount	Days Lag	Dollar Days
Disability Insurance	$ 86,324	(12.7)	$ (1,098,852)
401K Contributions	1,057,908	10.0	10,567,750
Pension	3,029,176	(70.3)	(212,805,112)
HSA Funding	262,810	8.8	2,317,225
Medical/Dental Insurance	1,469,351	(15.7)	(23,087,831)
Life Insurance	97,609	(12.7)	(1,244,071)
Total - Average Lag	$ 6,003,178	(37.5)	$ (225,350,891)

Dakota Electric Association
Cash Working Capital Analysis
Determination of Lag for Prepaid Insurance
Twelve Months Ending December 31, 2018

Description	Amount	Days Lag	Dollar Days
Workers Compensation	$ 194,743	(195.0)	$ (37,974,885)
Work Place Violance	840	(199.0)	(167,160)
General Liability, Property, Directors & Officers Liability	374,708	(173.0)	(64,824,484)
Total - Average Lag	$ 570,291	(180.6)	$ (102,966,529)

Dakota Electric Association
Cash Working Capital Analysis
Determination of Lag for FICA and Medicare
Twelve Months Ending December 31, 2018

Company Paid Payroll Taxes:

FICA	$ 1,071,963
Medicare	262,845
Total	$ 1,334,808

Employee Paid Payroll Taxes:

Salary	$ 2,284,610	11	$ 25,130,710
Hourly	2,159,652	18	38,873,736
Total	$ 4,444,262	14.4	$ 64,004,446

Payroll taxes are paid the Wednesday following payday for both payrolls. Therefore, the lag for salary payroll is equal to the lag for net payroll (6 days) plus 5 days, which equals 11 days; and the lag for hourly payroll is equal to the lag for net payroll (13 days) plus 5 days, which equals 18 days.

Dakota Electric Association

Cash Working Capital Analysis
Determination of Lag for Unemployment Taxes
Twelve Months Ending December 31, 2018

Federal Taxes		
First Quarter, 2018	$	8,179
Second Quarter, 2018		355
Third Quarter, 2018		317
Fourth Quarter, 2018		167
Subtotal	$	9,018
Minnesota State		
First Quarter, 2018	$	11,570
Second Quarter, 2018		4,420
Third Quarter, 2018		739
Fourth Quarter, 2018		439
Subtotal	$	17,168
Grand Total	$	26,186

Federal and state unemployment taxes are paid on the 15th of the month following the last month of the quarter. The lag is equal to 45 days (the midpoint of the quarter) plus 15 days, or 60 days total lag.

Dakota Electric Association

Cash Working Capital Analysis
Determination of Lag for Property and Real Estate Taxes
Twelve Months Ending December 31, 2018

			Service Period			Payment		
Description		**Amount**	**Start**	**Finish**	**Mid-Point**	**Date**	**Lag Days**	**Dollar Days**
Property Tax & 50% Real Estate Tax	(A)	$ 3,040,165	1-Jan-18	31-Dec-18	2-Jul-18	15-May-18	(48.0)	$ (145,927,920)
50% Real Estate Tax		392,277	1-Jan-18	31-Dec-18	2-Jul-18	15-Oct-18	105.0	41,189,085
Total - Average Lag		$ 3,432,442					(30.5)	$ (104,738,835)

Dakota Electric Association

Cash Working Capital Analysis
Determination of Lag for Sales, Use and Transit Tax
Twelve Months Ending December 31, 2018

Service Period				Date	Days	Dollar
Start	Finish	Mid-Point	Amount	Paid	Lag	Days
1-Jan-18	31-Jan-18	16-Jan-18	$ 1,019,618	20-Feb-18	35.0	$ 35,686,630
1-Feb-18	28-Feb-18	14-Feb-18	926,951	20-Mar-18	33.5	31,052,859
1-Mar-18	31-Mar-18	16-Mar-18	800,081	20-Apr-18	35.0	28,002,835
1-Apr-18	30-Apr-18	15-Apr-18	863,374	21-May-18	35.5	30,649,777
1-May-18	31-May-18	16-May-18	807,053	20-Jun-18	35.0	28,246,855
1-Jun-18	30-Jun-18	15-Jun-18	657,000	28-Jun-18	12.5	8,212,500
1-Jun-18	30-Jun-18	15-Jun-18	407,886	20-Aug-18	65.5	26,716,533
1-Jul-18	31-Jul-18	16-Jul-18	1,267,763	20-Aug-18	35.0	44,371,705
1-Aug-18	31-Aug-18	16-Aug-18	1,278,336	20-Sep-18	35.0	44,741,760
1-Sep-18	30-Sep-18	15-Sep-18	1,126,600	22-Oct-18	36.5	41,120,900
1-Oct-18	31-Oct-18	16-Oct-18	891,332	20-Nov-18	35.0	31,196,620
1-Nov-18	30-Nov-18	15-Nov-18	824,178	20-Dec-18	34.5	28,434,141
1-Dec-18	31-Dec-18	16-Dec-18	897,232	21-Jan-19	36.0	32,300,352
Total			$ 11,767,404		34.9	$ 410,733,467

Workpaper 5
Long Range Forecast

STATEMENT OF OPERATIONS - RUS FORM 325 C
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
A1. Additional Revenue to meet Drivers Goals				2,735,251	3,238,036	4,458,594	6,139,704	7,586,461	7,840,278	10,000,049	10,317,866	12,500,236	16,139,869
1. Operating Revenue and Patronage Capital	201,585,762	201,226,992	203,138,675	202,406,857	208,514,619	211,959,263	215,902,517	218,254,482	220,868,436	225,708,012	227,711,742	226,121,291	221,861,268
2. Power Production Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Cost of Purchased Power	148,623,624	147,874,758	149,330,034	149,397,033	154,233,073	157,296,497	160,805,319	162,813,811	164,966,045	169,314,301	170,938,007	168,937,190	165,455,176
C. Operating Revenue less Cost of Power	**52,962,138**	**53,352,234**	**53,808,641**	**55,745,075**	**57,519,582**	**59,121,360**	**61,236,902**	**63,027,132**	**63,742,670**	**66,393,761**	**67,091,600**	**69,684,338**	**72,545,961**
4. Transmission Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Regional Market Operations Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Distribution Expense - Operation	6,720,766	6,584,595	7,277,184	7,676,158	7,906,443	8,143,636	8,387,945	8,639,583	8,898,771	9,165,734	9,440,706	9,723,927	10,015,645
7. Distribution Expense - Maintenance	5,742,935	5,812,250	6,151,338	6,488,587	6,683,245	6,883,742	7,090,254	7,302,962	7,522,051	7,747,712	7,980,144	8,219,548	8,466,134
8. Consumer Accounts Expense	3,977,008	4,360,768	5,312,955	5,604,239	5,772,367	5,945,538	6,123,904	6,307,621	6,496,850	6,691,755	6,892,508	7,099,283	7,312,261
9. Customer Service and Informational Expense	3,919,789	4,099,386	3,585,760	3,782,350	3,895,821	4,012,696	4,133,076	4,257,069	4,384,781	4,516,324	4,651,814	4,791,368	4,935,109
10. Sales Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
11. Administrative and General Expense	10,503,325	11,341,864	11,907,838	12,560,689	12,937,510	13,325,635	13,725,404	14,137,166	14,561,281	14,998,120	15,448,063	15,911,505	16,388,850
12. Total Operation & Maintenance Expense (2 thru 11)	**179,487,447**	**180,073,621**	**183,565,109**	**185,509,057**	**191,428,458**	**195,607,743**	**200,265,903**	**203,458,212**	**206,829,778**	**212,433,946**	**215,351,242**	**214,682,821**	**212,573,176**
13. Depreciation & Amortization Expense	8,850,603	9,491,587	10,281,975	10,925,665	11,673,368	11,979,222	12,319,643	12,688,126	13,024,025	13,370,001	13,726,356	14,093,402	14,093,402
14. Tax Expense - Property & Gross Receipts	3,597,538	3,609,198	3,372,283	3,700,800	3,811,824	3,926,179	4,043,964	4,165,283	4,290,241	4,418,949	4,551,517	4,688,063	4,828,705
15. Tax Expense - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16. Interest on Long-Term Debt	4,169,404	3,747,120	3,741,685	3,980,592	4,219,414	4,546,866	4,878,004	5,268,409	5,700,353	6,105,420	6,575,101	7,109,903	7,709,837
17. Interest Charged to Construction (Credit)	0	0	0	0	0	0	0	0	0	0	0	0	0
18. Interest Expense - Other	259,115	447,606	549,008	759,783	757,000	796,500	836,000	880,500	920,000	959,500	999,000	1,038,500	1,078,000
19. Other Deductions	(37,218)	(22,241)	6,239	36,000	42,000	48,000	53,000	58,000	64,000	69,000	75,000	79,000	82,000
20. Total Cost of Electric Service (12 thru 19)	**196,326,889**	**197,346,891**	**201,516,299**	**204,911,896**	**211,932,064**	**216,904,510**	**222,396,514**	**226,518,530**	**230,828,398**	**237,356,815**	**241,278,216**	**241,691,689**	**240,365,119**
21. Patronage Capital & Operating Margins (1 minus 20)	**5,258,873**	**3,880,101**	**1,622,376**	**230,211**	**(179,409)**	**(486,653)**	**(354,293)**	**(677,587)**	**(2,119,683)**	**(1,648,754)**	**(3,248,609)**	**(3,070,162)**	**(2,363,982)**
22. Non Operating Margins - Interest	166,539	189,286	174,728	146,598	162,615	162,615	162,615	162,615	162,615	162,615	162,615	162,615	162,615
23. Allowance for Funds Used During Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
24. Income (Loss) from Equity Investments	(114,978)	(158,851)	8,227	0	0	0	0	0	0	0	0	0	0
25. Non Operating Margins - Other	(38,499)	67,576	110,023	287,845	288,000	288,000	288,000	288,000	288,000	288,000	288,000	288,000	288,000
26. Generation & Transmission Capital Credits	7,347,424	6,403,850	4,311,432	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030	3,934,030
27. CFC & Other Capital Credits & Patronage Dividends	869,880	761,693	799,780	664,675	595,228	618,239	641,326	670,790	703,528	733,615	768,921	809,254	856,032
28. Extraordinary Items	0	0	0	0	0	0	0	0	0	0	0	0	0
29. Patronage Capital or Margins (21 thru 28)	**13,489,239**	**11,143,655**	**7,026,566**	**5,263,358**	**4,800,464**	**4,516,230**	**4,671,677**	**4,377,847**	**2,968,489**	**3,469,505**	**1,904,956**	**2,123,736**	**2,876,694**
2. Cash Basis													
A. Cash from Operations before Debt Service				15,283,065	15,875,987	16,202,049	17,005,969	17,441,562	16,767,309	17,989,281	17,215,463	18,295,758	19,601,871
B. Total Debt Service				10,544,380	10,901,872	11,164,561	11,720,307	12,022,854	11,565,048	12,372,833	11,956,429	12,592,078	13,475,265
C. Cash Margins After Debt Service				**4,738,685**	**4,974,115**	**5,037,488**	**5,285,662**	**5,418,708**	**5,202,262**	**5,616,448**	**5,259,034**	**5,703,680**	**6,126,605**

GENERAL FUNDS SUMMARY - RUS FORM 325 D
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM Select	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. Summary of General Funds										
A. Net General Funds Beginning of Year	**325,778**	**1,465,319**	**1,734,627**	**1,462,628**	**1,397,874**	**1,411,646**	**1,121,585**	**1,158,239**	**907,199**	**892,105**
B. Cash Margins After Debt Service	4,738,685	4,974,115	5,037,488	5,285,662	5,418,708	5,202,262	5,616,448	5,259,034	5,703,680	6,126,605
C. Other Proceeds and changes in current assets or liabilitie	0	0	0	0	0	0	0	0	0	0
D. Sale of Excludable Items	0	0	0	0	0	0	0	0	0	0
E. Reimbursement of General Funds	0	0	0	0	0	0	0	0	0	0
F. Refund of Generation and Transmission Capital Credits	315,773	236,842	228,565	220,590	212,971	205,750	198,960	192,626	186,760	181,369
G. Uses of Cushion of Credit Account	0	0	0	0	0	0	0	0	0	0
H. Refund of CFC Capital Credits	217,733	239,979	316,228	353,901	379,749	374,512	371,009	408,558	405,599	429,659
I. Refund of Capital Term Certificates	0	0	0	0	0	0	0	117,997	0	0
2. Total General Funds Available	5,597,968	6,916,255	7,316,908	7,322,782	7,409,301	7,194,170	7,308,002	7,136,454	7,203,238	7,629,737
3. Proposed Uses of General Funds										
A. Purchase of Excludable Items	0	0	0	0	0	0	0	0	0	0
B. Capital Credits Retirements	2,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000	3,500,000
C. General Funds Invested in Plant	1,632,649	1,681,628	2,354,279	2,424,908	2,497,655	2,572,585	2,649,762	2,729,255	2,811,133	2,895,467
D. Purchase of Capital Term Certificates	0	0	0	0	0	0	0	0	0	0
E. Purchase of Member Capital Securities	0	0	0	0	0	0	0	0	0	0
F. Other Uses of General Funds	0	0	0	0	0	0	0	0	0	0
G. Additions to Cushion of Credit Account	0	0	0	0	0	0	0	0	0	0
H. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
4. Total Proposed Uses of General Funds	4,132,649	5,181,628	5,854,279	5,924,908	5,997,655	6,072,585	6,149,762	6,229,255	6,311,133	6,395,467
5. Net General Funds - End of Year	1,465,319	1,734,627	1,462,628	1,397,874	1,411,646	1,121,585	1,158,239	907,199	892,105	1,234,271

FINANCIAL FORECAST - RATIOS - RUS FORM 325 A
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
Ratios with Additional Revenue													
1. Equity	51.39%	51.52%	50.90%	50.85%	50.22%	49.72%	49.24%	48.59%	47.83%	47.17%	46.15%	45.16%	44.30%
2. Debt Service Coverage (DSC)	2.56	2.33	1.93	1.91	1.90	1.88	1.87	1.86	1.88	1.85	1.86	1.85	1.83
3. Times Interest Earned Ratio (TIER)	4.24	3.97	2.88	2.32	2.14	1.99	1.96	1.83	1.52	1.57	1.29	1.30	1.37
Revenue Comparison													
4. Average Revenue per MWH	$109.80	$109.52	$108.99	$112.58	$115.15	$116.82	$119.06	$120.42	$121.24	$124.27	$124.80	$124.43	$123.20
5. Increase in Average Revenue (Annual)				3.29%	2.29%	1.45%	1.92%	1.14%	0.69%	2.50%	0.43%	-0.30%	-0.98%
6. Total Utility Plant per MWH Sold	$156.97	$162.78	$164.48	$172.44	$175.96	$179.46	$183.17	$187.43	$191.12	$194.94	$198.88	$202.93	$206.72
Ratios to Total Utility Plant													
7. Net General Funds			0.11%	0.47%	0.54%	0.44%	0.41%	0.40%	0.31%	0.32%	0.24%	0.23%	0.31%
8. Depreciation and Amortization Reserve	40.93%	41.11%	41.41%	42.63%	43.48%	44.43%	45.36%	46.14%	47.21%	48.25%	49.25%	50.21%	51.05%
Ratios to Consumers													
9. Operations and Maintenance Expense	$118.73	$116.74	$125.02	$130.69	$133.34	$135.93	$138.76	$141.55	$144.36	$147.26	$150.23	$153.26	$156.39
10. Administrative and General Expense + Other Deductions	$99.70	$106.59	$110.92	$116.22	$118.63	$120.97	$123.52	$126.03	$128.58	$131.18	$133.86	$136.58	$139.37
Rate Information													
11. Plant Revenue Ratio	5.40	5.55	5.66	5.60	5.59	5.58	5.54	5.54	5.62	5.53	5.62	5.55	5.47
12. Rate of Return on Rate Base/1000 = 104% Net Utility Plant/1000	5.37%	4.20%	2.89%	2.26%	2.14%	2.13%	2.35%	2.35%	1.82%	2.25%	1.67%	2.02%	2.65%
13. Rate Base/1000 = 104% Net Utility Plant/1000	$175,686	$181,490	$185,580	$186,166	$188,860	$190,803	$192,787	$195,565	$196,605	$197,722	$198,919	$200,199	$201,957
14. Require Rate Increase over Present Rates				1.35%	1.55%	2.10%	2.84%	3.48%	3.55%	4.43%	4.53%	5.53%	7.27%
Modified Ratios													
15. Modified Debt Service Coverage (MDSC)	1.83	1.70	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
16. Modified Times Interest Earned Ratio (MTIER)	2.32	2.00	1.48	1.17	1.06	0.99	1.02	0.96	0.71	0.80	0.57	0.63	0.75
17. Operating Times Interest Earned Ratio (OTIER)	2.37	2.14	1.56	1.19	1.07	1.01	1.05	0.98	0.73	0.82	0.60	0.65	0.77
18. Operating Debt Service Coverage Ratio (ODSC)	1.81	1.67	1.48	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49

PRO FORMA BALANCE SHEET - RUS FORM 325 B
MN065

Dakota Electric Association

8/15/2019
Base 2018

	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
ASSETS AND OTHER DEBITS													
1. Total Utility Plant in Service	280,981,520	291,219,850	300,342,133	311,993,877	321,275,972	330,157,166	339,280,764	349,150,845	358,112,457	367,342,917	376,850,291	386,642,886	396,729,258
2. Construction Work in Progress	5,008,823	5,113,969	4,222,209										
3. Total Utility Plant (1+2)	**285,990,343**	**296,333,819**	**304,564,342**	**311,993,877**	**321,275,972**	**330,157,166**	**339,280,764**	**349,150,845**	**358,112,457**	**367,342,917**	**376,850,291**	**386,642,886**	**396,729,258**
4. Accum. Provision for Depreciation and Amort	117,061,473	121,824,590	126,121,950	132,988,585	139,680,132	146,692,701	153,908,505	161,107,296	169,069,380	177,225,582	185,581,726	194,143,809	202,539,952
5. Net Utility Plant (3-4)	**168,928,870**	**174,509,229**	**178,442,392**	**179,005,292**	**181,595,841**	**183,464,464**	**185,372,259**	**188,043,550**	**189,043,077**	**190,117,335**	**191,268,565**	**192,499,077**	**194,189,306**
6. Nonutility Property - Net	0	0	0	0	0	0	0	0	0	0	0	0	0
7. Investment in Subsidiary Companies	4,760,034	4,601,183	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409	4,609,409
8. Invest. in Assoc. Org. - Patronage Capital	105,707,320	112,381,152	116,936,898	121,002,097	125,054,535	129,062,011	133,062,875	137,074,975	141,132,271	145,229,947	149,331,714	153,482,639	157,661,673
9. Invest. in Assoc. Org. - Other - General Funds	0	0	0	0	0	0	0	0	0	0	0	0	0
10. Invest in Assoc. Org. - Other - Nongeneral Funds	4,685,675	4,627,795	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683	4,118,683
11. Investments in Economic Development Projects	0	0	0	0	0	0	0	0	0	0	0	0	0
12. Other Investments	0	0	0	0	0	0	0	0	0	0	0	0	0
13. Special Funds	0	0	0	0	0	0	0	0	0	0	0	0	0
14. Total Other Property & Investments (6 thru 13)	**115,153,029**	**121,610,130**	**125,664,990**	**129,730,189**	**133,782,627**	**137,790,103**	**141,790,967**	**145,803,067**	**149,860,363**	**153,958,039**	**158,059,806**	**162,210,731**	**166,389,765**
15. Cash-General Funds	988,866	142,650	325,778	1,465,319	1,734,627	1,462,628	1,397,874	1,411,646	1,121,585	1,158,239	907,199	892,105	1,234,271
16. Cash-Construction Funds-Trustee	0	0	0										
17. Special Deposits	0	0	0										
18. Temporary Investments	0	0	0										
19. Notes Receivable - Net	0	0	0										
20. Accounts Receivable - Net Sales of Energy	18,956,146	19,940,989	23,990,011										
21. Accounts Receivable - Net Other	556,998	440,745	850,182										
22. Renewable Energy Credits	0	0	0										
23. Materials & Supplies - Electric and Other	4,069,740	4,472,687	4,184,242										
24. Prepayments	1,018,547	976,797	1,314,991										
25. Other Current & Accrued Assets	3,181,369	5,194,535	5,086,132	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617	35,760,617
26. Total Current & Accrued Assets (15 thru 25)	**28,771,666**	**31,168,403**	**35,751,336**	**37,225,936**	**37,495,244**	**37,223,245**	**37,158,491**	**37,172,263**	**36,882,202**	**36,918,856**	**36,667,816**	**36,652,722**	**36,994,888**
27. Regulatory Assets	0	0	0										
28. Deferred Debits	1,014,188	1,100,624	335,059										
29. Total Assets & Other Debits (5+14+26+27)	**313,867,753**	**328,388,386**	**340,193,777**	**345,961,418**	**352,873,712**	**358,477,813**	**364,321,717**	**371,018,880**	**375,785,642**	**380,994,230**	**385,996,186**	**391,362,529**	**397,573,959**
LIABILITIES AND OTHER CREDITS													
30. Memberships	0	0	0										
31. Patronage Capital	47,557,568	49,104,028	49,353,994	175,914,526	177,214,989	178,231,219	179,402,896	180,280,744	179,749,233	179,718,738	178,123,694	176,747,430	176,124,124
32. Operating Margins - Prior Years	0	0	0										
33. Operating Margins - Current Year	5,258,876	3,880,101	1,622,376										
34. Non-Operating Margins	8,230,366	7,263,554	5,404,190										
35. Other Margins & Equities	100,247,381	108,951,375	116,770,607										
36. Total Margins & Equities (29 thru 34)	**161,294,191**	**169,199,058**	**173,151,167**	**175,914,526**	**177,214,989**	**178,231,219**	**179,402,896**	**180,280,744**	**179,749,233**	**179,718,738**	**178,123,694**	**176,747,430**	**176,124,124**
Long-Term Debt CFC (Net)	87,006,544	89,890,604	93,460,696	72,291,150	80,642,004	87,759,927	95,357,790	104,157,615	111,212,992	118,573,554	126,151,499	133,770,935	141,570,020
Long-Term Debt RUS (Net)	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt RUS - Econ. Devel. (Net)	0	0	0										
Long-Term Debt FFB - RUS - Guaranteed	0	0	0										
Long-Term Debt - Other RUS Guaranteed	0	0	0										
Long-Term Debt RUS - Unapplied (Cushion)	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt - Other (Net)	0	0	0	26,666,916	24,280,656	21,813,996	19,264,217	17,461,459	15,589,636	14,642,241	13,730,454	12,858,371	11,951,404
43. Total Long-Term Debt minus Unapplied	**87,006,544**	**89,890,604**	**93,460,696**	**98,958,066**	**104,922,660**	**109,573,923**	**114,622,007**	**121,619,074**	**126,802,628**	**133,215,796**	**139,881,953**	**146,629,305**	**153,521,424**
44. Obligations Under Capital Leases - Non current	591,885	767,576	1,379,543										
45. Accumulated Operating Provisions - Asset Retirement Obligations	3,925,000	4,207,000	4,609,000										
46. Total Other Noncurrent Liabilities (39+40)	**4,516,885**	**4,974,576**	**5,988,543**										
47. Notes Payable	12,500,000	13,600,000	20,734,355										
48. Accounts Payable	25,031,964	25,080,492	22,245,941										
49. Consumers Deposits	537,197	528,907	505,101										
50. Current Maturities Long-Term Debt	6,872,297	7,178,093	6,387,701	6,682,458	6,617,695	6,842,303	6,754,446	5,864,694	6,267,414	5,381,328	5,482,174	5,765,429	5,996,046
51. Current Maturities Long-Term Debt-Economic Dev.	0	0	0										
52. Current Maturities Capital Leases	355,935	517,185	512,662										
53. Other Current & Accrued Liabilities	11,934,854	12,607,375	12,800,350	64,406,368	64,118,368	63,830,368	63,542,368	63,254,368	62,966,368	62,678,368	62,508,365	62,220,365	61,932,365
54. Total Current & Accrued Liabilities (42 thru 48)	**57,232,247**	**59,512,052**	**63,186,110**	**71,088,826**	**70,736,063**	**70,672,671**	**70,296,814**	**69,119,062**	**69,233,782**	**68,059,696**	**67,990,539**	**67,985,794**	**67,928,411**
55. Regulatory Liabilities	0	0	0										
56. Deferred Credits	3,817,886	4,812,096	4,407,261										
57. Total Liabilities & Other Credits (35+38+41+49+50)	**313,867,753**	**328,388,386**	**340,193,777**	**345,961,418**	**352,873,712**	**358,477,813**	**364,321,717**	**371,018,880**	**375,785,642**	**380,994,230**	**385,996,186**	**391,362,529**	**397,573,959**

DETERMINATION OF LOAD - RUS FORM 325 E
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. Number of Consumers													
A. Residential	97,041	98,151	99,341	100,235	101,282	102,378	103,333	104,380	105,467	106,543	107,618	108,699	109,772
B. Residential - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Irrigation	392	391	391	392	396	397	398	399	400	401	402	403	404
D. Comm. and Ind. 1000 kVA or Less	4,395	4,451	4,489	4,535	4,445	4,446	4,447	4,448	4,449	4,450	4,451	4,452	4,453
E. Comm. and Ind. Over 1000 kVA	2,864	2,922	2,958	2,988	3,063	3,103	3,143	3,173	3,203	3,233	3,263	3,293	3,323
F. Public Street Lights & Highway Lighting	217	212	165	170	164	164	164	164	164	164	164	164	164
G. Other Sales to Public Authority	66	66	66	66	66	65	65	65	65	65	65	65	65
H. Sales for Resales - RUS Borrowers	0	0	0	0	0	0	0	0	0	0	0	0	0
I. Sales for Resales - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
J. Other 1	0	0	0	0	0	0	0	0	0	0	0	0	0
K. Other 2	0	0	0	0	0	0	0	0	0	0	0	0	0
L. Other 3	0	0	0	0	0	0	0	0	0	0	0	0	0
M. Mercury Vapor Lights	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CONSUMERS	**104,975**	**106,193**	**107,410**	**108,386**	**109,416**	**110,553**	**111,550**	**112,629**	**113,748**	**114,856**	**115,963**	**117,076**	**118,181**
2. Average Monthly KWH Usage per Consumer													
A. Residential	772	761	778	730	730	730	730	730	730	730	730	730	730
B. Residential - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Irrigation	1,489	1,705	1,894	1,629	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
D. Comm. and Ind. 1000 kVA or Less	834	824	815	813	796	786	776	771	766	761	756	751	750
E. Comm. and Ind. Over 1000 kVA	25,055	24,570	24,249	24,204	23,895	23,728	23,562	23,395	23,228	23,062	22,895	22,728	22,645
F. Public Street Lights & Highway Lighting	4,315	4,410	5,623	5,460	5,491	5,224	5,025	4,777	4,584	4,326	4,116	3,870	3,667
G. Other Sales to Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0
H. Sales for Resales - RUS Borrowers	0	0	0	0	0	0	0	0	0	0	0	0	0
I. Sales for Resales - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
J. Other 1	0	0	0	0	0	0	0	0	0	0	0	0	0
K. Other 2	0	0	0	0	0	0	0	0	0	0	0	0	0
L. Other 3	0	0	0	0	0	0	0	0	0	0	0	0	0
M. Mercury Vapor Lights	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Annual Power Requirements in MWHs													
A. Residential	898,635	895,738	927,054	878,338	887,230	896,831	905,197	914,369	923,891	933,317	942,734	952,203	961,603
B. Residential - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Irrigation	7,002	7,998	8,887	7,661	7,099	7,117	7,135	7,153	7,171	7,189	7,207	7,225	7,243
D. Comm. and Ind. 1000 kVA or Less	44,000	44,002	43,901	44,267	42,459	41,935	41,410	41,153	40,895	40,637	40,379	40,121	40,077
E. Comm. and Ind. Over 1000 kVA	861,102	861,533	860,725	867,899	878,285	883,536	888,664	890,788	892,791	894,713	896,477	898,120	902,992
F. Public Street Lights & Highway Lighting	11,236	11,218	11,134	11,138	10,807	10,281	9,889	9,402	9,022	8,513	8,100	7,617	7,216
G. Other Sales to Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0
H. Sales for Resales - RUS Borrowers	0	0	0	0	0	0	0	0	0	0	0	0	0
I. Sales for Resales - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
J. Other 1	0	0	0	0	0	0	0	0	0	0	0	0	0
K. Other 2	0	0	0	0	0	0	0	0	0	0	0	0	0
L. Other 3	0	0	0	0	0	0	0	0	0	0	0	0	0
M. Mercury Vapor Lights	0	0	0	0	0	0	0	0	0	0	0	0	0

DETERMINATION OF LOAD - RUS FORM 325 E
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
4. Annual Power Requirements in MWHs													
A. Total MWHs Sold	**1,821,975**	**1,820,489**	**1,851,701**	**1,809,303**	**1,825,880**	**1,839,701**	**1,852,296**	**1,862,865**	**1,873,771**	**1,884,370**	**1,894,897**	**1,905,286**	**1,919,131**
A1. Total MWHs Sold (No Line Loss)	0	0	0	0	0	0	0	0	0	0	0	0	0
B. System own Use	2,053	2,065	2,120	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075
C. System Loss Percentage (%)	2.60%	0.97%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
C1. System Loss Percentage (MWHs)	48,689	17,850	47,535	46,446	46,871	47,225	47,548	47,819	48,099	48,370	48,640	48,907	49,262
D. Total MWHs Purchased	**1,872,717**	**1,840,404**	**1,901,356**	**1,857,823**	**1,874,826**	**1,889,001**	**1,901,919**	**1,912,759**	**1,923,944**	**1,934,815**	**1,945,613**	**1,956,268**	**1,970,467**
E. Total MWH's Generated	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
F. Total MWH's Purchased and Generated	**1,872,717**	**1,840,404**	**1,901,356**	**1,857,823**	**1,874,826**	**1,889,001**	**1,901,919**	**1,912,759**	**1,923,944**	**1,934,815**	**1,945,613**	**1,956,268**	**1,970,467**

DETERMINATION OF OPERATING REVENUE - RUS FORM 325 F
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1 Residential													
A. Total Annual MWHs Sold	898,635	895,738	927,054	878,338	887,230	896,831	905,197	914,369	923,891	933,317	942,734	952,203	961,603
B. Average Revenue per MWH Sold	130.03	128.85	128.79	130.43	132.80	133.80	135.20	135.70	136.40	138.20	138.60	137.00	133.90
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	97,041	98,151	99,341	100,235	101,282	102,378	103,333	104,380	105,467	106,543	107,618	108,699	109,772
E. Annual Revenue less FlowThru Adjustment	**$ 116,849,882**	**$ 115,416,501**	**$ 119,397,405**	**$ 114,561,625**	**$ 117,824,186**	**$ 119,996,025**	**$ 122,382,645**	**$ 124,079,846**	**$ 126,018,721**	**$ 128,984,365**	**$ 130,662,888**	**$ 130,451,844**	**$ 128,758,604**
2 Residential - Seasonal													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
3 Irrigation													
A. Total Annual MWHs Sold	7,002	7,998	8,887	7,661	7,099	7,117	7,135	7,153	7,171	7,189	7,207	7,225	7,243
B. Average Revenue per MWH Sold	131.50	126.17	118.13	127.00	129.50	130.60	132.00	132.60	133.30	135.30	135.70	134.10	130.90
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	392	391	391	392	396	397	398	399	400	401	402	403	404
E. Annual Revenue less FlowThru Adjustment	**$ 920,785**	**$ 1,009,141**	**$ 1,049,852**	**$ 972,947**	**$ 919,384**	**$ 929,535**	**$ 941,865**	**$ 948,524**	**$ 955,921**	**$ 972,689**	**$ 977,997**	**$ 968,870**	**$ 948,097**
4 Comm. and Ind. 1000 kVA or Less													
A. Total Annual MWHs Sold	44,000	44,002	43,901	44,267	42,459	41,935	41,410	41,153	40,895	40,637	40,379	40,121	40,077
B. Average Revenue per MWH Sold	129.77	131.14	130.26	134.30	136.60	137.70	138.90	139.50	140.30	142.20	142.20	140.80	137.80
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	4,395	4,451	4,489	4,535	4,445	4,446	4,447	4,448	4,449	4,450	4,451	4,452	4,453
E. Annual Revenue less FlowThru Adjustment	**$ 5,709,677**	**$ 5,770,215**	**$ 5,718,527**	**$ 5,945,064**	**$ 5,799,850**	**$ 5,774,404**	**$ 5,751,913**	**$ 5,740,829**	**$ 5,737,598**	**$ 5,778,638**	**$ 5,741,961**	**$ 5,649,096**	**$ 5,522,611**
5 Comm. and Ind. Over 1000 kVA													
A. Total Annual MWHs Sold	861,102	861,533	860,725	867,899	878,285	883,536	888,664	890,788	892,791	894,713	896,477	898,120	902,992
B. Average Revenue per MWH Sold	86.54	87.18	85.52	89.20	91.60	92.60	93.90	94.50	95.10	97.00	97.30	95.80	92.70
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	2,864	2,922	2,958	2,988	3,063	3,103	3,143	3,173	3,203	3,233	3,263	3,293	3,323
E. Annual Revenue less FlowThru Adjustment	**$ 74,518,695**	**$ 75,108,588**	**$ 73,608,919**	**$ 77,416,587**	**$ 80,450,871**	**$ 81,815,416**	**$ 83,445,586**	**$ 84,179,468**	**$ 84,904,463**	**$ 86,787,195**	**$ 87,227,175**	**$ 86,039,862**	**$ 83,707,360**
6 Public Street Lights & Highway Lighting													
A. Total Annual MWHs Sold	11,236	11,218	11,134	11,138	10,807	10,281	9,889	9,402	9,022	8,513	8,100	7,617	7,216
B. Average Revenue per MWH Sold	181.76	184.93	183.54	184.20	186.70	188.10	188.40	189.40	190.50	193.10	191.60	190.80	188.10
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	217	212	165	170	164	164	164	164	164	164	164	164	164
E. Annual Revenue less FlowThru Adjustment	**$ 2,042,232**	**$ 2,074,506**	**$ 2,043,558**	**$ 2,051,576**	**$ 2,017,637**	**$ 1,933,944**	**$ 1,863,090**	**$ 1,780,687**	**$ 1,718,665**	**$ 1,643,878**	**$ 1,552,055**	**$ 1,453,283**	**$ 1,357,330**
7 Other Sales to Public Authority													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
D. Average Number of Consumers	66	66	66	66	66	65	65	65	65	65	65	65	65
E. Annual Revenue less FlowThru Adjustment	**$ 3,900**	**$ 3,900**	**$ 3,960**	**$ 3,960**	**$ 3,940**	**$ 3,924**	**$ 3,920**	**$ 3,923**	**$ 3,925**	**$ 3,928**	**$ 3,925**	**$ 3,921**	**$ 3,916**
8 Sales for Resales - RUS Borrowers													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
9 Sales for Resales - Other													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

DETERMINATION OF OPERATING REVENUE - RUS FORM 325 F
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
10 Other 1													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
11 Other 2													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12 Other 3													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
13 Mercury Vapor Lights													
A. Total Annual MWHs Sold	0	0	0	0	0	0	0	0	0	0	0	0	0
B. Average Revenue per MWH Sold	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Fixed Monthly Charge per Consumer	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Average Number of Consumers	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Annual Revenue less FlowThru Adjustment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
14 Flow Through Adjustments													
A. MWHs Sold Subject to Adjustment 1	1,821,975	1,820,489	1,851,701	1,809,303	1,825,880	1,839,701	1,852,296	1,862,865	1,873,771	1,884,370	1,894,897	1,905,286	1,919,131
B. Flow Through Adjustment 1 per MWH	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Revenue From Adjustment 1	-	-	-	-	-	-	-	-	-	-	-	-	-
D. MWHs Sold Subject to Adjustment 2	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Flow Through Adjustment 2 per MWH	-	-	-	-	-	-	-	-	-	-	-	-	-
F. Revenue From Adjustment 2	-	-	-	-	-	-	-	-	-	-	-	-	-
G. Total Revenue From Adjustments	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
15. Revenue from Sale of Electric Energy	**$ 200,045,171**	**$ 199,382,851**	**$ 201,822,221**	**$ 200,951,759**	**$ 207,015,868**	**$ 210,453,248**	**$ 214,389,019**	**$ 216,733,277**	**$ 219,339,293**	**$ 224,170,693**	**$ 226,166,001**	**$ 224,566,876**	**$ 220,297,918**
16. Other Operating Revenue	**$ 1,540,591**	**$ 1,844,141**	**$ 1,316,454**	**$ 1,455,098**	**$ 1,498,751**	**$ 1,506,015**	**$ 1,513,498**	**$ 1,521,205**	**$ 1,529,143**	**$ 1,537,319**	**$ 1,545,741**	**$ 1,554,415**	**$ 1,563,350**
17. Total Operating Revenue	**$ 201,585,762**	**$ 201,226,992**	**$ 203,138,675**	**$ 202,406,857**	**$ 208,514,619**	**$ 211,959,263**	**$ 215,902,517**	**$ 218,254,482**	**$ 220,868,436**	**$ 225,708,012**	**$ 227,711,742**	**$ 226,121,291**	**$ 221,861,268**

PLANT INVESTMENTS & LOAN REQUIREMENTS - RUS FORM 325 G
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. A. Total Utility Plant (Beginning of Year)	278,435,831	285,990,343	296,333,819	304,564,342	311,993,877	321,275,972	330,157,166	339,280,764	349,150,845	358,112,457	367,342,917	376,850,291	386,642,886
B. Plant Additions and Replacements	10,614,472	14,862,509	14,741,870	11,488,565	14,263,917	13,847,845	14,227,438	15,359,416	14,023,552	14,444,259	14,877,586	15,323,914	15,783,631
C. Construction Work in Progress	5,008,823	5,113,969	4,222,209										
D. Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Retirements	4,393,148	4,624,179	5,619,587	4,059,030	4,981,822	4,966,652	5,103,840	5,489,335	5,061,940	5,213,799	5,370,213	5,531,319	5,697,258
F. Total Utility Plant (End of Year)	**285,990,343**	**296,333,819**	**304,564,342**	**311,993,877**	**321,275,972**	**330,157,166**	**339,280,764**	**349,150,845**	**358,112,457**	**367,342,917**	**376,850,291**	**386,642,886**	**396,729,258**
2. Analysis of Priority Funds													
A. Distribution	8,026,549	12,445,146	9,744,293	9,574,300	12,292,224	11,194,799	11,494,800	12,544,800	11,124,497	11,458,232	11,801,979	12,156,038	12,520,719
B. Headquarters	256,327	267,556	370,501	281,616	290,065	298,766	307,729	316,961	326,470	336,264	346,352	356,743	367,445
C. Other Needs - Loan	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Generation and Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Warehouse	0	0	0	0	0	0	0	0	0	0	0	0	0
F. Reimbursement of General Funds				0	0	0	0	0	0	0	0	0	0
G. Total of Priority Items	**8,282,876**	**12,712,702**	**10,114,794**	**9,855,916**	**12,582,288**	**11,493,566**	**11,802,530**	**12,861,761**	**11,450,967**	**11,794,496**	**12,148,331**	**12,512,781**	**12,888,164**
LESS: H. Contribution in Aid of Construction				0	0	0	0	0	0	0	0	0	0
I. General Funds Invested in Plant				0	0	0	0	0	0	0	0	0	0
J. Loan Funds Required for Priority Items				9,855,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
K1. Prior RUS Loan Funds Required				0	0	0	0	0	0	0	0	0	0
K2. Prior CFC Loan Funds Required				0	0	0	0	0	0	0	0	0	0
L. New Joint Loans Funds Required				9,855,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
M. New Loans From RUS				0	0	0	0	0	0	0	0	0	0
N. New Loans From CFC				9,855,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
O. New Loans From NCSC				0	0	0	0	0	0	0	0	0	0
P. New Loans From FARMER MAC				0	0	0	0	0	0	0	0	0	0
Q. New Loans From Other Sources				0	0	0	0	0	0	0	0	0	0
3. Analysis of Non-Priority Funds													
A. General Plant Additions	2,331,596	2,149,807	4,627,076	1,632,649	1,681,628	2,354,280	2,424,908	2,497,656	2,572,585	2,649,763	2,729,256	2,811,133	2,895,467
B. Other Needs - General Funds	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
C. Total Non-Priority Funds Required				**1,632,649**	**1,681,628**	**2,354,279**	**2,424,908**	**2,497,655**	**2,572,585**	**2,649,762**	**2,729,255**	**2,811,133**	**2,895,467**
4. Analysis of General Funds Invested in Plant													
A. General Funds Invested in Plant - Non-Priority				1,632,649	1,681,628	2,354,279	2,424,908	2,497,655	2,572,585	2,649,762	2,729,255	2,811,133	2,895,467
B. General Funds Invested in Plant - Priority				0	0	0	0	0	0	0	0	0	0
C. Total General Funds Invested in Plant				1,632,649	1,681,628	2,354,279	2,424,908	2,497,655	2,572,585	2,649,762	2,729,255	2,811,133	2,895,467
5. Plant Investment Summary													
A. New Loans From RUS				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
B. New Loans From CFC				**9,855,916**	**12,582,288**	**11,493,566**	**11,802,530**	**12,861,761**	**11,450,967**	**11,794,496**	**12,148,331**	**12,512,781**	**12,888,164**
C. New Loans From NCSC				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
D. New Loans From FARMER MAC				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
C. Loan Funds Required - Others				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
D. Total New Loans Required From Others				**9,855,916**	**12,582,288**	**11,493,566**	**11,802,530**	**12,861,761**	**11,450,967**	**11,794,496**	**12,148,331**	**12,512,781**	**12,888,164**

DETERMINATION OF DEBT AND DEBT SERVICE - CFC FORM 325 I MN065				Dakota Electric Association									8/15/2019 Base 2018
CFC Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
9022001													
1. A. Year/ Month	2018	12	E. Balance Beginning	1,585,363	1,164,148	728,540	277,820	0	0	0	0	0	0
B. Original Amount / Payments per Year	1,585,363	4	F. Plus Interest	48,532	34,138	19,026	4,108	0	0	0	0	0	0
C. Amort. Period / Deferral	3.59	0.00	H. Less Discounts	1,785	1,252	701	152	0	0	0	0	0	0
D. Amortization Type	Level Debt Service		I. Less Payments	467,961	468,494	469,045	281,776	0	0	0	0	0	0
E. Interest Rate / Loan Type	3.40000%	Fixed	J. Balance End of year	1,164,148	728,540	277,820	0	0	0	0	0	0	0
9029001													
2. A. Year/ Month	2018	12	E. Balance Beginning	2,082,541	1,847,221	1,601,368	1,344,027	1,074,909	793,475	499,263	191,484	0	0
B. Original Amount / Payments per Year	2,082,541	4	F. Plus Interest	89,745	79,212	67,724	55,947	43,631	30,852	17,287	3,750	0	0
C. Amort. Period / Deferral	7.59	0.00	H. Less Discounts	2,494	2,195	1,882	1,555	1,213	855	481	105	0	0
D. Amortization Type	Level Debt Service		I. Less Payments	322,572	322,870	323,183	323,510	323,852	324,210	324,584	195,129	0	0
E. Interest Rate / Loan Type	4.50000%	Fixed	J. Balance End of year	1,847,221	1,601,368	1,344,027	1,074,909	793,475	499,263	191,484	0	0	0
9036002													
3. A. Year/ Month	2018	12	E. Balance Beginning	1,766,030	1,663,598	1,557,145	1,446,124	1,330,538	1,210,199	1,085,051	954,617	818,821	677,441
B. Original Amount / Payments per Year	1,766,030	4	F. Plus Interest	69,965	65,943	61,376	56,811	52,058	47,248	41,964	36,600	31,016	25,280
C. Amort. Period / Deferral	13.33	0.00	H. Less Discounts	2,160	2,030	1,895	1,754	1,607	1,454	1,296	1,130	958	778
D. Amortization Type	Level Debt Service		I. Less Payments	170,237	170,367	170,502	170,643	170,790	170,942	171,101	171,267	171,439	171,618
E. Interest Rate / Loan Type	4.05000%	Fixed	J. Balance End of year	1,663,598	1,557,145	1,446,124	1,330,538	1,210,199	1,085,051	954,617	818,821	677,441	530,325
9038001													
4. A. Year/ Month	2018	12	E. Balance Beginning	2,218,947	2,091,953	1,959,726	1,821,538	1,677,383	1,527,002	1,370,312	1,206,672	1,035,965	857,887
B. Original Amount / Payments per Year	2,218,947	4	F. Plus Interest	92,277	87,044	81,083	75,116	68,891	62,581	55,631	48,565	41,193	33,606
C. Amort. Period / Deferral	13.33	0.00	H. Less Discounts	2,714	2,553	2,385	2,210	2,027	1,836	1,637	1,429	1,212	986
D. Amortization Type	Level Debt Service		I. Less Payments	216,557	216,718	216,886	217,062	217,245	217,435	217,635	217,842	218,059	218,285
E. Interest Rate / Loan Type	4.25000%	Fixed	J. Balance End of year	2,091,953	1,959,726	1,821,538	1,677,383	1,527,002	1,370,312	1,206,672	1,035,965	857,887	672,222
9039001													
5. A. Year/ Month	2018	12	E. Balance Beginning	2,465,360	2,317,056	2,163,721	2,004,720	1,840,081	1,669,603	1,493,244	1,310,467	1,121,208	925,237
B. Original Amount / Payments per Year	2,465,360	4	F. Plus Interest	84,336	79,305	73,639	68,001	62,162	56,281	49,863	43,381	36,669	29,811
C. Amort. Period / Deferral	13.33	0.00	H. Less Discounts	3,697	2,825	2,630	2,429	2,220	2,005	1,781	1,550	1,310	1,062
D. Amortization Type	Level Debt Service		I. Less Payments	228,943	229,815	230,009	230,211	230,419	230,635	230,859	231,090	231,330	231,578
E. Interest Rate / Loan Type	3.50000%	Fixed	J. Balance End of year	2,317,056	2,163,721	2,004,720	1,840,081	1,669,603	1,493,244	1,310,467	1,121,208	925,237	722,408

DETERMINATION OF DEBT AND DEBT SERVICE - CFC FORM 325 I
MN065

Dakota Electric Association

8/15/2019
Base 2018

CFC Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
9040003													
6. A. Year/ Month	2018	12	E. Balance Beginning	3,794,320	3,504,388	3,203,656	2,890,956	2,566,204	2,228,934	1,878,902	1,515,140	1,137,357	745,012
B. Original Amount / Payments per Year	3,794,320	4	F. Plus Interest	140,046	129,246	117,279	105,226	92,708	79,947	66,216	52,195	37,634	22,591
C. Amort. Period / Deferral	10.83	0.00	H. Less Discounts	9,215	5,045	4,591	3,462	3,051	2,623	2,179	1,718	1,239	742
D. Amortization Type	Level Debt Service		I. Less Payments	420,764	424,933	425,387	426,516	426,928	427,355	427,799	428,260	428,739	429,237
E. Interest Rate / Loan Type	3.80000%	Fixed	J. Balance End of year	3,504,388	3,203,656	2,890,956	2,566,204	2,228,934	1,878,902	1,515,140	1,137,357	745,012	337,625
9042001													
7. A. Year/ Month	2018	12	E. Balance Beginning	11,379,844	11,002,726	10,613,140	10,208,439	9,789,179	9,354,837	8,905,803	8,439,680	7,956,788	7,456,525
B. Original Amount / Payments per Year	11,379,844	4	F. Plus Interest	398,935	386,467	371,353	356,793	341,710	327,019	309,930	293,162	275,789	258,537
C. Amort. Period / Deferral	20.83	0.00	H. Less Discounts	28,095	27,142	26,153	23,433	20,070	16,937	14,140	11,238	9,712	9,079
D. Amortization Type	Level Debt Service		I. Less Payments	747,958	748,911	749,900	752,620	755,983	759,116	761,914	764,816	766,341	766,974
E. Interest Rate / Loan Type	3.55000%	Fixed	J. Balance End of year	11,002,726	10,613,140	10,208,439	9,789,179	9,354,837	8,905,803	8,439,680	7,956,788	7,456,525	6,939,009
9043001													
8. A. Year/ Month	2018	12	E. Balance Beginning	4,704,028	4,562,900	4,417,150	4,265,701	4,108,804	3,946,262	3,778,267	3,603,834	3,423,126	3,235,917
B. Original Amount / Payments per Year	4,704,028	4	F. Plus Interest	165,102	160,481	154,781	149,333	143,689	138,235	131,797	125,522	119,021	112,609
C. Amort. Period / Deferral	22.33	0.00	H. Less Discounts	11,627	11,271	10,901	10,517	10,119	9,708	9,282	8,840	7,260	4,920
D. Amortization Type	Level Debt Service		I. Less Payments	294,603	294,960	295,330	295,713	296,111	296,522	296,948	297,390	298,970	301,310
E. Interest Rate / Loan Type	3.55000%	Fixed	J. Balance End of year	4,562,900	4,417,150	4,265,701	4,108,804	3,946,262	3,778,267	3,603,834	3,423,126	3,235,917	3,042,296
9044001													
9. A. Year/ Month	2018	12	E. Balance Beginning	4,337,267	4,228,976	4,117,014	4,000,347	3,879,243	3,753,534	3,623,440	3,488,002	3,347,413	3,201,478
B. Original Amount / Payments per Year	4,337,267	4	F. Plus Interest	161,112	157,441	152,736	148,299	143,693	139,309	133,965	128,814	123,468	118,256
C. Amort. Period / Deferral	24.83	0.00	H. Less Discounts	10,741	10,467	10,183	9,887	9,580	9,262	8,931	8,588	8,232	7,862
D. Amortization Type	Level Debt Service		I. Less Payments	258,662	258,936	259,220	259,516	259,823	260,141	260,471	260,815	261,171	261,541
E. Interest Rate	3.75000%	Fixed	J. Balance End of year	4,228,976	4,117,014	4,000,347	3,879,243	3,753,534	3,623,440	3,488,002	3,347,413	3,201,478	3,050,331
9044002													
10. A. Year/ Month	2018	12	E. Balance Beginning	1,917,161	1,754,430	1,586,424	1,412,643	1,233,056	1,047,468	855,777	657,584	452,770	241,112
B. Original Amount / Payments per Year	1,917,161	4	F. Plus Interest	61,249	55,974	50,198	44,392	38,392	32,289	25,787	19,165	12,322	5,273
C. Amort. Period / Deferral	10.08	0.00	H. Less Discounts	4,641	4,229	3,804	3,364	2,909	2,440	1,955	1,453	935	399
D. Amortization Type	Level Debt Service		I. Less Payments	219,339	219,751	220,176	220,616	221,070	221,540	222,025	222,527	223,045	223,581
E. Interest Rate	3.30000%	Fixed	J. Balance End of year	1,754,430	1,586,424	1,412,643	1,233,056	1,047,468	855,777	657,584	452,770	241,112	22,406
9044004													
11. A. Year/ Month	2018	12	E. Balance Beginning	1,309,090	1,017,028	717,667	410,681	95,948	0	0	0	0	0
B. Original Amount / Payments per Year	1,309,090	4	F. Plus Interest	29,984	22,685	15,059	7,312	691	0	0	0	0	0
C. Amort. Period / Deferral	4.33	0.00	H. Less Discounts	3,000	2,263	1,508	733	70	0	0	0	0	0
D. Amortization Type	Level Debt Service		I. Less Payments	319,046	319,783	320,538	321,313	96,569	0	0	0	0	0
E. Interest Rate	2.50000%	Fixed	J. Balance End of year	1,017,028	717,667	410,681	95,948	0	0	0	0	0	0

DETERMINATION OF DEBT AND DEBT SERVICE - CFC FORM 325 I
MN065

Dakota Electric Association

8/15/2019
Base 2018

CFC Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
9044005													
12. A. Year/ Month	2018	12	E. Balance Beginning	4,705,933	4,565,591	4,420,591	4,269,838	4,113,584	3,951,628	3,784,163	3,610,187	3,429,863	3,242,959
B. Original Amount / Payments per Year	4,705,933	4	F. Plus Interest	167,507	162,848	157,095	151,594	145,892	140,383	133,872	127,524	120,944	114,453
C. Amort. Period / Deferral	22.33	0.00	H. Less Discounts	11,633	11,278	10,910	10,528	10,132	9,722	9,297	8,857	8,400	7,927
D. Amortization Type	Level Debt Service		I. Less Payments	296,215	296,570	296,938	297,320	297,716	298,126	298,551	298,992	299,448	299,921
E. Interest Rate	3.60000%	Fixed	J. Balance End of year	4,565,591	4,420,591	4,269,838	4,113,584	3,951,628	3,784,163	3,610,187	3,429,863	3,242,959	3,049,564
9045001													
13. A. Year/ Month	2018	12	E. Balance Beginning	9,749,608	9,487,146	9,215,703	8,932,936	8,639,414	8,334,730	8,019,339	7,691,073	7,350,322	6,996,613
B. Original Amount / Payments per Year	9,749,608	4	F. Plus Interest	361,892	352,913	341,587	330,833	319,671	308,964	296,089	283,605	270,646	257,933
C. Amort. Period / Deferral	23.58	0.00	H. Less Discounts	24,127	23,463	22,773	22,056	21,312	20,542	19,740	18,908	18,044	17,149
D. Amortization Type	Level Debt Service		I. Less Payments	600,228	600,892	601,582	602,299	603,043	603,813	604,615	605,447	606,311	607,206
E. Interest Rate	3.75000%	Fixed	J. Balance End of year	9,487,146	9,215,703	8,932,936	8,639,414	8,334,730	8,019,339	7,691,073	7,350,322	6,996,613	6,630,191
9045002													
14. A. Year/ Month	2018	12	E. Balance Beginning	9,957,793	9,783,338	9,602,525	9,412,729	9,214,736	9,008,194	8,793,816	8,569,098	8,334,676	8,090,131
B. Original Amount / Payments per Year	9,957,793	4	F. Plus Interest	420,390	414,032	405,049	396,853	388,303	380,467	370,127	360,423	350,300	340,713
C. Amort. Period / Deferral	29.33	0.00	H. Less Discounts	24,729	24,288	23,827	23,345	22,842	22,319	21,773	21,202	20,607	19,987
D. Amortization Type	Level Debt Service		I. Less Payments	570,116	570,557	571,018	571,500	572,003	572,526	573,072	573,643	574,238	574,858
E. Interest Rate / Loan Type	4.25000%	Fixed	J. Balance End of year	9,783,338	9,602,525	9,412,729	9,214,736	9,008,194	8,793,816	8,569,098	8,334,676	8,090,131	7,835,999
Subtotal Debt and Debt Service - CFC													
A. Debt - First of Year				61,973,284	58,990,498	55,904,370	52,698,499	49,563,078	46,825,866	44,087,376	41,237,839	38,408,310	35,670,313
B. New Funds - Advanced													
C. Interest Expense				2,291,071	2,187,729	2,067,986	1,950,619	1,841,492	1,743,576	1,632,528	1,522,706	1,419,003	1,319,062
D. Performance Discounts				76,069	72,296	68,380	64,340	60,633	57,254	53,777	50,179	46,731	43,264
E. Collateral Discounts				0	0	0	0	0	0	0	0	0	0
F. Equity Discounts				0	0	0	0	0	0	0	0	0	0
G. Volume Discounts				64,588	58,006	55,761	51,084	46,519	42,450	38,715	34,838	31,177	27,628
H. Less Discounts				140,657	130,301	124,141	115,425	107,152	99,704	92,492	85,017	77,908	70,892
I. Debt Payments				5,133,200	5,143,556	5,149,716	4,970,615	4,471,553	4,382,361	4,389,573	4,267,217	4,079,092	4,086,109
J. Debt - End of Year				58,990,498	55,904,370	52,698,499	49,563,078	46,825,866	44,087,376	41,237,839	38,408,310	35,670,313	32,832,375

DETERMINATION OF DEBT AND DEBT SERVICE - RUS FORM 325 I - Other Lender
MN065

Dakota Electric Association

8/15/2019
Base 2018

Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
0													
1. A. Year/ Month	2018	12	E. Balance Beginning	3,841,338	3,112,984	2,365,393	1,597,600	809,290	0	0	0	0	0
B. Original Amount / Payments per Year	3,841,338	12	F. Plus Interest	92,578	73,341	53,139	32,622	11,557	0	0	0	0	0
C. Amort. Period / Deferral	5.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	820,932	820,932	820,932	820,932	820,846	0	0	0	0	0
E. Interest Rate / Loan Type	2.64000%	vel Debt Serv	J. Balance End of year	3,112,984	2,365,393	1,597,600	809,290	0	0	0	0	0	0
0													
2. A. Year/ Month	2018	12	E. Balance Beginning	1,059,986	481,549	0	0	0	0	0	0	0	0
B. Original Amount / Payments per Year	1,059,986	12	F. Plus Interest	35,548	9,562	0	0	0	0	0	0	0	0
C. Amort. Period / Deferral	1.75	0.00											
D. Amortization Type	Monthly		I. Less Payments	613,985	491,111	0	0	0	0	0	0	0	0
E. Interest Rate / Loan Type	4.47000%	vel Debt Serv	J. Balance End of year	481,549	0	0	0	0	0	0	0	0	0
0													
3. A. Year/ Month	2018	12	E. Balance Beginning	4,904,209	4,743,536	4,576,610	4,402,046	4,220,082	4,030,401	3,833,151	3,627,063	3,412,237	3,188,302
B. Original Amount / Payments per Year	4,904,209	12	F. Plus Interest	200,931	194,677	187,041	179,639	171,923	164,354	155,516	146,778	137,668	128,547
C. Amort. Period / Deferral	20.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	361,604	361,604	361,604	361,604	361,604	361,604	361,604	361,604	361,604	361,604
E. Interest Rate / Loan Type	4.16000%	vel Debt Serv	J. Balance End of year	4,743,536	4,576,610	4,402,046	4,220,082	4,030,401	3,833,151	3,627,063	3,412,237	3,188,302	2,955,245
0													
4. A. Year/ Month	2018	12	E. Balance Beginning	1,088,704	977,010	861,372	741,451	617,191	488,434	355,066	216,824	73,580	0
B. Original Amount / Payments per Year	1,088,704	12	F. Plus Interest	36,932	32,987	28,706	24,366	19,870	15,258	10,384	5,382	758	0
C. Amort. Period / Deferral	8.58	0.00											
D. Amortization Type	Monthly		I. Less Payments	148,626	148,626	148,626	148,626	148,626	148,626	148,626	148,626	74,338	0
E. Interest Rate / Loan Type	3.56000%	vel Debt Serv	J. Balance End of year	977,010	861,372	741,451	617,191	488,434	355,066	216,824	73,580	0	0
0													
5. A. Year/ Month	2018	12	E. Balance Beginning	4,332,287	4,236,755	4,137,262	4,032,506	3,922,795	3,807,895	3,688,062	3,562,061	3,430,101	3,291,899
B. Original Amount / Payments per Year	4,332,287	12	F. Plus Interest	198,535	194,575	189,312	184,357	179,168	174,235	168,067	162,107	155,866	149,763
C. Amort. Period / Deferral	24.75	0.00											
D. Amortization Type	Monthly		I. Less Payments	294,068	294,068	294,068	294,068	294,068	294,068	294,068	294,068	294,068	294,068
E. Interest Rate / Loan Type	4.63000%	vel Debt Serv	J. Balance End of year	4,236,755	4,137,262	4,032,506	3,922,795	3,807,895	3,688,062	3,562,061	3,430,101	3,291,899	3,147,594

DETERMINATION OF DEBT AND DEBT SERVICE - RUS FORM 325 I - Other Lender
MN065

Dakota Electric Association

8/15/2019
Base 2018

Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
0													
6. A. Year/ Month	2018	12	E. Balance Beginning	3,433,732	3,277,427	3,115,108	2,945,788	2,769,552	2,586,118	2,395,483	2,196,770	1,989,940	1,774,662
B. Original Amount / Payments per Year	3,433,732	12	F. Plus Interest	134,807	128,794	121,793	114,877	107,679	100,478	92,400	84,283	75,835	67,242
C. Amort. Period / Deferral	16.00	0.00											
D. Amortization Type	Monthly		I. Less Payments	291,113	291,113	291,113	291,113	291,113	291,113	291,113	291,113	291,113	291,113
E. Interest Rate / Loan Type	4.01000%	/el Debt Serv	J. Balance End of year	3,277,427	3,115,108	2,945,788	2,769,552	2,586,118	2,395,483	2,196,770	1,989,940	1,774,662	1,550,791
0													
7. A. Year/ Month	2018	12	E. Balance Beginning	4,574,903	3,985,922	3,376,978	2,746,627	2,094,507	1,419,866	722,058	0	0	0
B. Original Amount / Payments per Year	4,574,903	12	F. Plus Interest	146,353	126,390	104,983	83,214	60,693	37,525	13,296	0	0	0
C. Amort. Period / Deferral	7.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	735,334	735,334	735,334	735,334	735,334	735,334	735,354	0	0	0
E. Interest Rate / Loan Type	3.40000%	/el Debt Serv	J. Balance End of year	3,985,922	3,376,978	2,746,627	2,094,507	1,419,866	722,058	0	0	0	0
0													
8. A. Year/ Month	2018	12	E. Balance Beginning	3,738,278	3,643,759	3,545,783	3,443,381	3,336,785	3,225,825	3,110,687	2,990,469	2,865,327	2,735,061
B. Original Amount / Payments per Year	3,738,278	12	F. Plus Interest	148,522	145,066	140,639	136,446	132,081	127,904	122,823	117,900	112,775	107,751
C. Amort. Period / Deferral	24.00	0.00											
D. Amortization Type	Monthly		I. Less Payments	243,041	243,041	243,041	243,041	243,041	243,041	243,041	243,041	243,041	243,041
E. Interest Rate / Loan Type	4.02000%	/el Debt Serv	J. Balance End of year	3,643,759	3,545,783	3,443,381	3,336,785	3,225,825	3,110,687	2,990,469	2,865,327	2,735,061	2,599,771
0													
9. A. Year/ Month	2018	12	E. Balance Beginning	167,115	0	0	0	0	0	0	0	0	0
B. Original Amount / Payments per Year	167,115	12	F. Plus Interest	1,779	0	0	0	0	0	0	0	0	0
C. Amort. Period / Deferral	1.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	168,894	0	0	0	0	0	0	0	0	0
E. Interest Rate	1.97000%	/el Debt Serv	J. Balance End of year	0	0	0	0	0	0	0	0	0	0
0													
10. A. Year/ Month	2018	12	E. Balance Beginning	1,546,883	1,344,045	1,135,538	920,991	700,337	473,402	240,043	0	0	0
B. Original Amount / Payments per Year	1,546,883	12	F. Plus Interest	40,849	35,180	29,140	23,033	16,752	10,328	3,650	0	0	0
C. Amort. Period / Deferral	7.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	243,687	243,687	243,687	243,687	243,687	243,687	243,693	0	0	0
E. Interest Rate	2.81000%	/el Debt Serv	J. Balance End of year	1,344,045	1,135,538	920,991	700,337	473,402	240,043	0	0	0	0
0													
11. A. Year/ Month	2018	12	E. Balance Beginning	3,745,754	3,651,045	3,552,873	3,450,266	3,343,458	3,232,276	3,116,908	2,996,449	2,871,057	2,740,530
B. Original Amount / Payments per Year	3,745,754	12	F. Plus Interest	148,819	145,356	140,921	136,719	132,345	128,160	123,068	118,136	113,001	107,967
C. Amort. Period / Deferral	24.08	0.00											
D. Amortization Type	Monthly		I. Less Payments	243,528	243,528	243,528	243,528	243,528	243,528	243,528	243,528	243,528	243,528
E. Interest Rate	4.02000%	/el Debt Serv	J. Balance End of year	3,651,045	3,552,873	3,450,266	3,343,458	3,232,276	3,116,908	2,996,449	2,871,057	2,740,530	2,604,970
Subtotal Debt and Debt Service - Other Lender													
A. Debt - First of Year				32,433,190	29,454,032	26,666,916	24,280,656	21,813,996	19,264,217	17,461,459	15,589,636	14,642,241	13,730,454
B. New Funds - Advanced													
C. Interest Expense				1,185,654	1,085,927	995,672	915,273	832,068	758,242	689,203	634,585	595,904	561,270
E. Debt Payments				4,164,812	3,873,044	3,381,933	3,381,933	3,381,847	2,561,001	2,561,026	1,581,980	1,507,691	1,433,353
F. Debt - End of Year				29,454,032	26,666,916	24,280,656	21,813,996	19,264,217	17,461,459	15,589,636	14,642,241	13,730,454	12,858,371

DETERMINATION OF DEBT AND DEBT SERVICE - CFC FORM 325 I - NEW CFC DEBT
MN065

Dakota Electric Association

8/15/2019
Base 2018

Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
2019 CFC													
1. A. Year/ Month	2019	6	E. Balance Beginning	0	12,268,115	12,082,313	11,885,301	11,678,252	11,460,655	11,233,603	10,993,353	10,740,863	10,475,511
B. Original Amount / Payments per Year	12,355,916	4	F. Plus Interest	310,887	611,575	600,364	590,328	579,779	570,324	557,127	544,887	532,024	519,995
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts	15,417	30,495	30,018	29,516	28,989	28,438	27,857	27,245	26,602	25,929
D. Amortization Type	Level Debt Service		I. Less Payments	383,271	766,882	767,358	767,860	768,387	768,939	769,520	770,132	770,775	771,448
E. Interest Rate / Loan Type	5.00000%	Fixed	J. Balance End of year	12,268,115	12,082,313	11,885,301	11,678,252	11,460,655	11,233,603	10,993,353	10,740,863	10,475,511	10,198,129
2020 CFC													
2. A. Year/ Month	2020	6	E. Balance Beginning		0	12,492,879	12,301,896	12,101,184	11,890,247	11,670,254	11,437,363	11,192,607	10,935,382
B. Original Amount / Payments per Year	12,582,288	4	F. Plus Interest		316,583	621,003	611,273	601,048	591,993	579,094	567,229	554,760	543,211
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts		15,699	31,050	30,564	30,052	29,518	28,955	28,362	27,738	27,086
D. Amortization Type	Level Debt Service		I. Less Payments		390,293	780,935	781,422	781,933	782,467	783,030	783,623	784,247	784,899
E. Interest Rate / Loan Type	5.00000%	Fixed	J. Balance End of year		12,492,879	12,301,896	12,101,184	11,890,247	11,670,254	11,437,363	11,192,607	10,935,382	10,666,608
2021 CFC													
3. A. Year/ Month	2021	6	E. Balance Beginning			0	11,411,892	11,237,435	11,054,091	10,862,977	10,660,556	10,447,822	10,224,250
B. Original Amount / Payments per Year	11,493,566	4	F. Plus Interest			289,189	567,269	558,381	550,612	539,304	528,992	518,154	508,218
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts			14,341	28,363	27,919	27,455	26,965	26,450	25,908	25,341
D. Amortization Type	Level Debt Service		I. Less Payments			356,522	713,362	713,807	714,271	714,760	715,276	715,818	716,384
E. Interest Rate / Loan Type	5.00000%	Fixed	J. Balance End of year			11,411,892	11,237,435	11,054,091	10,862,977	10,660,556	10,447,822	10,224,250	9,990,742
2022 CFC													
4. A. Year/ Month	2022	6	E. Balance Beginning				0	11,722,622	11,551,129	11,372,183	11,181,927	10,981,484	10,770,309
B. Original Amount / Payments per Year	11,802,530	4	F. Plus Interest				311,838	612,000	604,545	593,236	583,049	572,317	562,622
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts				14,728	29,143	28,709	28,249	27,764	27,253	26,718
D. Amortization Type	Level Debt Service		I. Less Payments				377,018	754,349	754,783	755,243	755,728	756,239	756,774
E. Interest Rate / Loan Type	5.25000%	Fixed	J. Balance End of year				11,722,622	11,551,129	11,372,183	11,181,927	10,981,484	10,770,309	10,549,439
2023 CFC													
5. A. Year/ Month	2023	6	E. Balance Beginning					0	12,778,844	12,602,021	12,413,263	12,213,908	12,003,360
B. Original Amount / Payments per Year	12,861,761	4	F. Plus Interest					356,035	701,081	689,147	678,549	667,356	657,420
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts					16,051	31,780	31,325	30,843	30,334	29,801
D. Amortization Type	Level Debt Service		I. Less Payments					422,901	846,125	846,579	847,061	847,570	848,104
E. Interest Rate / Loan Type	5.50000%	Fixed	J. Balance End of year					12,778,844	12,602,021	12,413,263	12,213,908	12,003,360	11,782,876

DETERMINATION OF DEBT AND DEBT SERVICE - CFC FORM 325 I - NEW CFC DEBT
MN065

Dakota Electric Association

8/15/2019
Base 2018

Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
2024 CFC													
6. A. Year/ Month	2024	6	E. Balance Beginning						0	11,380,717	11,228,422	11,067,179	10,896,463
B. Original Amount / Payments per Year	11,450,967	4	F. Plus Interest						331,416	651,036	642,088	632,615	624,377
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts						14,291	28,306	27,917	27,505	27,072
D. Amortization Type	Level Debt Service		I. Less Payments						387,374	775,026	775,414	775,826	776,259
E. Interest Rate / Loan Type	5.75000%	Fixed	J. Balance End of year						11,380,717	11,228,422	11,067,179	10,896,463	10,717,509
2025 CFC													
7. A. Year/ Month	2025	6	E. Balance Beginning							0	11,725,684	11,575,693	11,416,497
B. Original Amount / Payments per Year	11,794,496	4	F. Plus Interest							356,227	700,086	690,882	683,076
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts							14,721	29,170	28,787	28,383
D. Amortization Type	Level Debt Service		I. Less Payments							410,318	820,907	821,291	821,694
E. Interest Rate / Loan Type	6.00000%	Fixed	J. Balance End of year							11,725,684	11,575,693	11,416,497	11,249,496
2026 CFC													
8. A. Year/ Month	2026	6	E. Balance Beginning								0	12,080,971	11,933,304
B. Original Amount / Payments per Year	12,148,331	4	F. Plus Interest								382,229	751,510	744,203
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts								15,164	30,060	29,686
D. Amortization Type	Level Debt Service		I. Less Payments								434,425	869,118	869,492
E. Interest Rate / Loan Type	6.25000%	Fixed	J. Balance End of year								12,080,971	11,933,304	11,778,329
2027 CFC													
9. A. Year/ Month	2027	6	E. Balance Beginning									0	12,446,887
B. Original Amount / Payments per Year	12,512,781	4	F. Plus Interest									409,472	807,732
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts									15,620	30,981
D. Amortization Type	Level Debt Service		I. Less Payments									459,746	919,751
E. Interest Rate	6.50000%	Fixed	J. Balance End of year									12,446,887	12,303,887
2028 CFC													
10. A. Year/ Month	2028	6	E. Balance Beginning										0
B. Original Amount / Payments per Year	12,888,164	4	F. Plus Interest										438,007
C. Amort. Period / Deferral	30.00	0.00	H. Less Discounts										16,090
D. Amortization Type	Level Debt Service		I. Less Payments										486,333
E. Interest Rate	6.75000%	Fixed	J. Balance End of year										12,823,750
Total Debt and Debt Service - CFC NEW DEBT													
A. Debt - First of Year				0	12,268,115	24,575,192	35,599,090	46,739,494	58,734,966	69,121,755	79,640,568	90,300,528	101,101,964
B. New Funds - Advanced				12,355,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
C. Interest Expense				310,887	928,158	1,510,557	2,080,707	2,707,243	3,349,971	3,965,170	4,627,110	5,329,091	6,088,861
D. Performance Discounts				7,709	23,097	37,705	51,586	66,077	80,095	93,189	106,457	119,904	133,543
E. Collateral Discounts				0	0	0	0	0	0	0	0	0	0
F. Equity Discounts				0	0	0	0	0	0	0	0	0	0
G. Volume Discounts				7,709	23,097	37,705	51,586	66,077	80,095	93,189	106,457	119,904	133,543
H. Less Discounts				15,417	46,194	75,409	103,171	132,154	160,191	186,378	212,914	239,807	267,087
I. Debt Payments				383,271	1,157,175	1,904,815	2,639,662	3,441,377	4,253,958	5,054,475	5,902,566	6,800,628	7,751,137
J. Debt - End of Year				12,268,115	24,575,192	35,599,090	46,739,494	58,734,966	69,121,755	79,640,568	90,300,528	101,101,964	112,060,765

DETERMINATION OF DEBT AND DEBT SERVICE - FARMER MAC FORM 325 I
MN065

Dakota Electric Association

8/15/2019
Base 2018

FARMER MAC Note Information				Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
3000001													
1. A. Year/ Month	2018	12	E. Balance Beginning	2,816,884	2,730,551	2,640,819	2,546,883	2,448,891	2,346,667	2,240,312	2,129,081	2,013,048	1,892,003
B. Original Amount / Payments per Year	3,291,847	4	F. Plus Interest	118,333	114,933	110,730	106,674	102,442	98,310	93,435	88,632	83,622	78,622
C. Amort. Period / Deferral	20.76	0.00											
D. Amortization Type	Level Debt Service		I. Less Payments	204,666	204,666	204,666	204,666	204,666	204,666	204,666	204,666	204,666	204,666
E. Interest Rate / Loan Type	4.25000%	Fixed	J. Balance End of year	2,730,551	2,640,819	2,546,883	2,448,891	2,346,667	2,240,312	2,129,081	2,013,048	1,892,003	1,765,960
3001001													
2. A. Year/ Month	2018	12	E. Balance Beginning	1,632,746	1,330,572	1,016,801	690,695	351,919	0	0	0	0	0
B. Original Amount / Payments per Year	3,341,081	4	F. Plus Interest	58,196	46,599	34,264	21,594	8,431	0	0	0	0	0
C. Amort. Period / Deferral	5.01	0.00											
D. Amortization Type	Level Debt Service		I. Less Payments	360,370	360,370	360,370	360,370	360,350	0	0	0	0	0
E. Interest Rate / Loan Type	3.83000%	Fixed	J. Balance End of year	1,330,572	1,016,801	690,695	351,919	0	0	0	0	0	0
3002001													
3. A. Year/ Month	2018	12	E. Balance Beginning	992,292	866,755	736,256	600,403	459,074	312,052	159,139	0	0	0
B. Original Amount / Payments per Year	1,698,652	4	F. Plus Interest	37,525	32,564	27,208	21,734	16,039	10,150	3,953	0	0	0
C. Amort. Period / Deferral	7.01	0.00											
D. Amortization Type	Level Debt Service		I. Less Payments	163,062	163,062	163,062	163,062	163,062	163,062	163,092	0	0	0
E. Interest Rate / Loan Type	3.97000%	Fixed	J. Balance End of year	866,755	736,256	600,403	459,074	312,052	159,139	0	0	0	0

Subtotal Debt and Debt Service - FARMER MAC	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A. Debt - First of Year	5,441,922	4,927,878	4,393,876	3,837,981	3,259,884	2,658,719	2,399,451	2,129,081	2,013,048	1,892,003
B. New Funds - Advanced										
C. Interest Expense	214,054	194,096	172,202	150,001	126,912	108,460	97,388	88,632	83,622	78,622
E. Debt Payments	728,098	728,098	728,098	728,098	728,078	367,728	367,758	204,666	204,666	204,666
F. Debt - End of Year	4,927,878	4,393,876	3,837,981	3,259,884	2,658,719	2,399,451	2,129,081	2,013,048	1,892,003	1,765,960

DETERMINATION OF DEBT AND DEBT SERVICE TOTAL - CFC FORM 325 J
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. Debt and Debt Service - RUS Existing Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
2. Debt and Debt Service - RUS Unadvanced Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
3. Debt and Debt Service - RUS New Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
4. Debt and Debt Service - CFC Existing Loans										
A. Debt First of Year	61,973,284	58,990,498	55,904,370	52,698,499	49,563,078	46,825,866	44,087,376	41,237,839	38,408,310	35,670,313
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	2,291,071	2,187,729	2,067,986	1,950,619	1,841,492	1,743,576	1,632,528	1,522,706	1,419,003	1,319,062
D. Less Discounts	140,657	130,301	124,141	115,425	107,152	99,704	92,492	85,017	77,908	70,892
D. Principal Payments	2,982,786	3,086,128	3,205,871	3,135,421	2,737,212	2,738,490	2,849,538	2,829,529	2,737,997	2,837,938
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	5,133,200	5,143,556	5,149,716	4,970,615	4,471,553	4,382,361	4,389,573	4,267,217	4,079,092	4,086,109
G. Debt End of Year	58,990,498	55,904,370	52,698,499	49,563,078	46,825,866	44,087,376	41,237,839	38,408,310	35,670,313	32,832,375

DETERMINATION OF DEBT AND DEBT SERVICE TOTAL - CFC FORM 325 J
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
5. Debt and Debt Service - CFC Unadvanced Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Less Discounts	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
6. Debt and Debt Service - CFC New Loans										
A. Debt First of Year	0	12,268,115	24,575,192	35,599,090	46,739,494	58,734,966	69,121,755	79,640,568	90,300,528	101,101,964
B. Loan Funds Advanced	12,355,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
C. Interest	310,887	928,158	1,510,557	2,080,707	2,707,243	3,349,971	3,965,170	4,627,110	5,329,091	6,088,861
D. Less Discounts	15,417	46,194	75,409	103,171	132,154	160,191	186,378	212,914	239,807	267,087
D. Principal Payments	87,801	275,211	469,668	662,126	866,289	1,064,178	1,275,683	1,488,371	1,711,345	1,929,363
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	383,271	1,157,175	1,904,815	2,639,662	3,441,377	4,253,958	5,054,475	5,902,566	6,800,628	7,751,137
G. Debt End of Year	12,268,115	24,575,192	35,599,090	46,739,494	58,734,966	69,121,755	79,640,568	90,300,528	101,101,964	112,060,765
7. Debt and Debt Service - NCSC Existing Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
8. Debt and Debt Service - NCSC New Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0

DETERMINATION OF DEBT AND DEBT SERVICE TOTAL - CFC FORM 325 J
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
9. Debt and Debt Service - Farmer Mac Existing Loans										
A. Debt First of Year	5,441,922	4,927,878	4,393,876	3,837,981	3,259,884	2,658,719	2,399,451	2,129,081	2,013,048	1,892,003
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	214,054	194,096	172,202	150,001	126,912	108,460	97,388	88,632	83,622	78,622
D. Principal Payments	514,044	534,002	555,895	578,096	601,166	259,268	270,370	116,034	121,044	126,044
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	728,098	728,098	728,098	728,098	728,078	367,728	367,758	204,666	204,666	204,666
G. Debt End of Year	4,927,878	4,393,876	3,837,981	3,259,884	2,658,719	2,399,451	2,129,081	2,013,048	1,892,003	1,765,960
10. Debt and Debt Service - Farmer Mac New Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0
11. Debt and Debt Service - Other Existing Loans										
A. Debt First of Year	32,433,190	29,454,032	26,666,916	24,280,656	21,813,996	19,264,217	17,461,459	15,589,636	14,642,241	13,730,454
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	1,185,654	1,085,927	995,672	915,273	832,068	758,242	689,203	634,585	595,904	561,270
D. Principal Payments	2,979,157	2,787,116	2,386,260	2,466,660	2,549,779	1,802,758	1,871,823	947,394	911,787	872,084
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	4,164,812	3,873,044	3,381,933	3,381,933	3,381,847	2,561,001	2,561,026	1,581,980	1,507,691	1,433,353
G. Debt End of Year	29,454,032	26,666,916	24,280,656	21,813,996	19,264,217	17,461,459	15,589,636	14,642,241	13,730,454	12,858,371
12. Debt and Debt Service - Other New Loans										
A. Debt First of Year	0	0	0	0	0	0	0	0	0	0
B. Loan Funds Advanced	0	0	0	0	0	0	0	0	0	0
C. Interest	0	0	0	0	0	0	0	0	0	0
D. Principal Payments	0	0	0	0	0	0	0	0	0	0
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	0	0	0	0	0	0	0	0	0	0
G. Debt End of Year	0	0	0	0	0	0	0	0	0	0

DETERMINATION OF DEBT AND DEBT SERVICE TOTAL - CFC FORM 325 J
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
13. Debt and Debt Service - Total Loans										
A. Debt First of Year	99,848,396	105,640,524	111,540,354	116,416,226	121,376,453	127,483,768	133,070,041	138,597,124	145,364,127	152,394,734
B. Loan Funds Advanced	12,355,916	12,582,288	11,493,566	11,802,530	12,861,761	11,450,967	11,794,496	12,148,331	12,512,781	12,888,164
C. Interest	4,001,666	4,395,909	4,746,417	5,096,600	5,507,715	5,960,248	6,384,290	6,873,033	7,427,619	8,047,815
D. Less Discounts	156,074	176,495	199,550	218,596	239,306	259,895	278,870	297,932	317,716	337,978
D. Principal Payments	6,563,789	6,682,458	6,617,695	6,842,303	6,754,446	5,864,694	6,267,414	5,381,328	5,482,174	5,765,429
E. Additional Principal Payments	0	0	0	0	0	0	0	0	0	0
F. Total Payments	10,409,380	10,901,872	11,164,561	11,720,307	12,022,854	11,565,048	12,372,833	11,956,429	12,592,078	13,475,265
G. Debt End of Year	105,640,524	111,540,354	116,416,226	121,376,453	127,483,768	133,070,041	138,597,124	145,364,127	152,394,734	159,517,470

DETERMINATION OF OPERATING EXPENSES - RUS FORM 325 K
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Historical 2016	Historical 2017	Historical 2018	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. A. Total MWHs Required	1,872,717	1,840,404	1,901,356	1,857,823	1,874,826	1,889,001	1,901,919	1,912,759	1,923,944	1,934,815	1,945,613	1,956,268	1,970,467
B. Cost per MWH Purchased	79.36	80.35	78.54	80.42	82.27	83.27	84.55	85.12	85.74	87.51	87.86	86.36	83.97
C. Flow Through Adjustment - MWH													
D. Cost of Purchased Power	148,623,624	147,874,758	149,330,034	149,397,033	154,233,073	157,296,497	160,805,319	162,813,811	164,966,045	169,314,301	170,938,007	168,937,190	165,455,176
2. A. Consumer Accounts Expense	7,896,797	8,460,154	8,898,715	9,386,590	9,668,188	9,958,233	10,256,980	10,564,690	10,881,630	11,208,079	11,544,322	11,890,651	12,247,371
B. Cost per Consumer Served	75.23	79.67	82.85	86.60	88.36	90.08	91.95	93.80	95.66	97.58	99.55	101.56	103.63
C. Average Number of Consumers	104,975	106,193	107,410	108,386	109,416	110,553	111,550	112,629	113,748	114,856	115,963	117,076	118,181
3. A. Operations and Maintenance Expense	12,463,701	12,396,845	13,428,522	14,164,745	14,589,687	15,027,378	15,478,199	15,942,545	16,420,822	16,913,446	17,420,850	17,943,475	18,481,780
B. Ratio to Total Utility Plant	4.36	4.18	4.41	4.54	4.54	4.55	4.56	4.57	4.59	4.60	4.62	4.64	4.66
4. A. Administration and General Expense	10,503,325	11,341,864	11,907,838	12,560,689	12,937,510	13,325,635	13,725,404	14,137,166	14,561,281	14,998,120	15,448,063	15,911,505	16,388,850
B. Ratio to Total Utility Plant	3.67	3.83	3.91	4.03	4.03	4.04	4.05	4.05	4.07	4.08	4.10	4.12	4.13
5. A. Depreciation & Amortization Expense	8,850,603	9,491,587	10,281,975	10,925,665	11,673,368	11,979,222	12,319,643	12,688,126	13,024,025	13,370,001	13,726,356	14,093,402	14,093,402
B. Ratio to Total Utility Plant	3.09	3.20	3.38	3.50	3.63	3.63	3.63	3.63	3.64	3.64	3.64	3.65	3.55
6. A. Tax Expense	3,597,538	3,609,198	3,372,283	3,700,800	3,811,824	3,926,179	4,043,964	4,165,283	4,290,241	4,418,949	4,551,517	4,688,063	4,828,705
B. Ratio to Total Utility Plant	1.26	1.22	1.11	1.19	1.19	1.19	1.19	1.19	1.20	1.20	1.21	1.21	1.22
7. A. Discount on Debt				171,491	222,690	274,960	321,767	371,460	420,086	465,248	510,846	557,523	605,065
8. A. Total Utility Plant	285,990,343	296,333,819	304,564,342	311,993,877	321,275,972	330,157,166	339,280,764	349,150,845	358,112,457	367,342,917	376,850,291	386,642,886	396,729,258

DETERMINATION OF CFC - TRANSACTIONS - CFC FORM 325 L
MN065

Dakota Electric Association

8/15/2019
Base 2018

ITEM	Future 2019	Future 2020	Future 2021	Future 2022	Future 2023	Future 2024	Future 2025	Future 2026	Future 2027	Future 2028
1. Equity Investment in CFC (First Year)										
A. Subscriptions CTC's	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841	1,418,841
B. Member Capital Securities	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
C. Loan CTC's (Prior 1983)	532,350	532,350	532,350	532,350	532,350	532,350	532,350	532,350	532,350	532,350
D. Loan CTC's (After 1983)	1,191,860	1,191,860	1,191,860	1,191,860	1,191,860	1,191,860	1,191,860	1,191,860	1,073,863	1,073,863
E. CFC Patronage Capital	4,260,228	4,707,171	5,062,420	5,364,431	5,651,856	5,942,897	6,271,913	6,634,519	6,994,882	7,398,537
Total Equity Investment	**8,403,279**	**8,850,222**	**9,205,471**	**9,507,482**	**9,794,907**	**10,085,948**	**10,414,964**	**10,777,570**	**11,019,936**	**11,423,591**
Loan CTCs Required	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2. Changes in Equity Investment in CFC										
A. Purchase of Loan CTC's	0	0	0	0	0	0	0	0	0	0
B. Purchase of Member Capital Securities	0	0	0	0	0	0	0	0	0	0
C. Refund of Loan CTC's	0	0	0	0	0	0	0	117,997	0	0
D. Patronage Capital Accrual	664,675	595,228	618,239	641,326	670,790	703,528	733,615	768,921	809,254	856,032
E. Patronage Capital Rotation	217,733	239,979	316,228	353,901	379,749	374,512	371,009	408,558	405,599	429,659
Total Equity Changes	**446,942**	**355,249**	**302,011**	**287,425**	**291,041**	**329,016**	**362,606**	**242,365**	**403,655**	**426,373**
3. Income from Investments in CFC										
A. Interest from Subscription CTC's	70,942	70,942	70,942	70,942	70,942	70,942	70,942	70,942	70,942	70,942
B. Interest from Member Capital Securities	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
C. Interest from Pre 1983 Loan CTC's	15,971	15,971	15,971	15,971	15,971	15,971	15,971	15,971	15,971	15,971
D. Patronage Capital Income	664,675	595,228	618,239	641,326	670,790	703,528	733,615	768,921	809,254	856,032
Total Income CFC Equity	**801,587**	**732,141**	**755,151**	**778,238**	**807,703**	**840,441**	**870,528**	**905,833**	**946,166**	**992,945**

Workpaper 4
2019 Budget

Dakota Electric Association
2019 Budget

Account - Description	2017 Actual	2018 Actual	2019 Budget	% Chg to '18 Actual
Revenue				
62000-65000 - Rate Revenue	199,382,850	201,822,220	200,967,995	-0.4%
65020-65040 - Total Trackers	994,532	155,939	235,098	-50.8%
65510-65560 - Charges & Fees	849,609	1,160,515	1,220,000	5.1%
66010 - Miscellaneous Sales	53,540	49,233	20,520	-58.3%
66030 - Rent-Elec Prop-Cable TV/Tel	152,643	156,791	153,601	-2.0%
66195 - Interco-Support & Occupancy	8,729	6,129		-100.0%
66210 - Energy Product Sales	133,681	150,090	150,822	0.5%
66310 - Utility Services Revenue	435,085	428,972	347,380	-19.0%
66315 - Engineering Svcs Revenue	191,048	100,232	33,000	-67.1%
66320 - Rev-Emp Inventoried Tool Sale	1,739	1,253	2,600	107.5%
66325 - Billable Project Revenue	19,511			N/A
Total Revenue	**202,222,967**	**204,031,374**	**203,131,016**	**-0.4%**
Power Cost				
70110 - Purchased Power - Capacity	32,898,219	33,126,800	33,959,792	2.5%
70115 - GRE PCA Adjustment - Capacity	526,561	(389,799)	0	-100.0%
70116 - A/C Control Credit - $6R/$2C&I	(891,128)	(901,924)	(772,584)	-14.3%
70120 - Purchased Power - Energy	89,878,020	95,391,286	94,502,720	-0.9%
70121 - KWH Credit - Off Peak Sales	(720,020)	(796,695)	(806,494)	1.2%
70125 - GRE PCA Adjustment - Energy	273,693	(2,761,760)	0	-100.0%
70140 - Purch Power - Trans/Ancillary	25,846,826	25,595,905	22,463,459	-12.2%
70190 - Wellspring Wind Energy	33,962	35,411	19,722	-44.3%
70191 - Wellspring Solar Energy	2,394	2,895	3,648	26.0%
70205 - Purchased Power - Generation Credit	(37)	(14)	0	N/A
70210 - Purchased Power - Other	26,269	27,930	27,060	-3.1%
Total Power Cost	147,874,759	149,330,035	149,397,323	0.0%
Other Cost of Sales				
71010 - Miscellaneous - COS	20,345	18,843	4,500	-76.1%
71210 - Energy Products - COS	125,238	147,183	145,664	-1.0%
71310 - Utility Services - COS	209,453	239,887	176,914	-26.3%
71312 - Utlty Svcs-Inventory COS	63,126	100,655	61,000	-39.4%
71315 - Engineering Services-COS	125,527	57,412	21,000	-63.4%
71320 - Inventoried Tools Employee COS	1,434	1,176	2,000	70.1%
71325 - Billable Projects - COS	19,511	5,145	0	-100.0%
71370 - Communication Fee - COS	8,400	8,255	9,000	9.0%
Total Other Cost of Sales	573,034	578,556	420,078	-27.4%
Total Cost of Sales	**148,447,793**	**149,908,591**	**149,817,401**	**-0.1%**
Gross Margin	**53,775,174**	**54,122,783**	**53,313,615**	**-1.5%**
Labor				
81110 - Salaries	8,322,344	8,793,264	9,029,080	2.7%
81120 - Wages	6,083,493	6,339,959	6,765,015	6.7%
81125 - Overtime	442,988	548,877	514,933	-6.2%
81130 - Part Time	112,594	126,034	137,214	8.9%
81190 - Other Pay	175,166	200,240	80,244	-59.9%
81199 - Payroll Overheads	214,401	243,510	250,420	2.8%
81220 - Temporary Help	123,567	88,807	98,395	10.8%
Total Labor	15,474,553	16,340,691	16,875,301	3.3%

Dakota Electric Association
2019 Budget

Account - Description	2017 Actual	2018 Actual	2019 Budget	% Chg to '18 Actual
Payroll Taxes				
81410 - FICA	1,092,504	1,159,549	1,175,968	1.4%
81420 - FUTA	8,129	8,241	7,330	-11.1%
81430 - SUTA	17,084	15,613	14,621	-6.4%
Total Payroll Taxes	1,117,717	1,183,403	1,197,919	1.2%
Insurance/Pension				
81510 - Medical & Dental Insurance	1,531,414	1,657,000	1,788,418	7.9%
81515 - Other Medical Expense	295,495	258,269	262,401	1.6%
81520 - Life Insurance	81,482	84,336	95,265	13.0%
81530 - 401K Expense	835,647	914,071	1,026,652	12.3%
81531 - 401K Adminisration Fee	58,524	50,738	52,000	2.5%
81540 - Pension Expense	2,498,839	2,587,633	2,567,123	-0.8%
81541 - Pension Administration Fees	84,467	92,851	94,591	1.9%
81550 - Post-Employment 106 Benefits	414,228	539,650	147,377	
Total Insurance/Pension	5,800,096	6,184,548	6,033,827	-2.4%
Total Internal Labor	**22,392,366**	**23,708,642**	**24,107,047**	**1.7%**
Other Benefits				
81610 - Education & Training Fees	79,802	102,032	140,060	37.3%
81620 - Tuition Aid	7,773	700	3,000	328.6%
81630 - Employee Physicals	17,678	9,834	25,500	159.3%
81640 - Employee Clothing	134,939	119,577	124,050	3.7%
81650 - Employee Functions & Awards	21,108	18,504	41,000	121.6%
81660 - Recruiting Expense	30,026	59,355	35,000	-41.0%
81665 - Other Hiring Expense	1,862	13,902	8,000	-42.5%
81690 - Other Benefits Expense	77,118	61,057	58,200	-4.7%
Total Other Benefits	370,306	384,961	434,810	12.9%
External Labor				
81230 - Contract Help	1,197,746	1,268,744	1,266,390	-0.2%
Total External Labor	1,197,746	1,268,744	1,266,390	-0.2%
Professional Fees & Services				
82110 - Attorney Fees	89,183	147,262	129,000	-12.4%
82120 - Auditor Fees	36,205	35,055	40,000	14.1%
82140 - Consultant Fees	323,424	450,666	570,500	26.6%
82150 - Customer Surveys	15,100	19,420	8,000	-58.8%
82160 - Contracted Services-Other	1,920,132	2,428,184	3,126,023	28.7%
82210 - Filing Fees	387,007	410,200	439,000	7.0%
82220 - Miscellaneous Fees	80,728	78,875	85,688	8.6%
82310 - Bank Service Charge	49,257	64,972	129,774	99.7%
82410 - Board Fees	372,153	377,995	383,225	1.4%
Total Prof Fees & Services	3,273,189	4,012,629	4,911,210	22.4%

Dakota Electric Association
2019 Budget

Account - Description	2017 Actual	2018 Actual	2019 Budget	% Chg to '18 Actual
Corporate Insurance				
82510 - Property Insurance	88,374	80,651	82,236	2.0%
82520 - Workers Comp Insurance	151,934	188,060	210,646	12.0%
82530 - Gen Liability & Umbrella	227,730	229,717	232,956	1.4%
82550 - Gen Claims & Settlements	1,746	2,446	2,400	-1.9%
Total Corp Insurance	469,784	500,874	528,238	5.5%
Advertising/Promotion				
83010 - Radio Ads	6,618	6,848	6,800	-0.7%
83015 - Television Advertising	93,250	108,605	138,330	27.4%
83020 - Digital Advertising	36,158	41,631	43,300	4.0%
83025 - Newspaper Advertising	28,718	11,090	18,125	63.4%
83030 - Other Ads	16,464	15,282	18,960	24.1%
83035 - Directory Advertising	19,671	20,064	20,295	1.2%
83040 - Bill Inserts	40,796	43,765	50,050	14.4%
83060 - Billboards/Signs	4,042	0	0	N/A
83200 - Photography & Supplies	1,777	1,679	2,450	45.9%
83300 - Promotional Items	54,245	42,768	59,393	38.9%
83410 - Grants	500	500	20,500	4000.0%
83420 - Rebates	2,592,743	1,851,587	1,744,490	-5.8%
83500 - Registration	2,320	2,285	2,500	9.4%
85160 - Product Warranties	7,514	10,367	8,960	-13.6%
Total Advertising/Promo	2,904,816	2,156,471	2,134,153	-1.0%
Supplies & Office				
83610 - Dues & Memberships	317,555	325,544	337,281	3.6%
84110 - Supplies-Office	66,398	62,997	64,769	2.8%
84120 - Outside Printing	226,849	213,156	219,545	3.0%
84130 - Computer Hardware	68,857	129,415	83,428	-35.5%
84140 - Computer Software	38,936	29,802	48,499	62.7%
84150 - Office Machine Lease or Rental	8,047	8,022	8,328	3.8%
84160 - Office Equip & Software Maint	555,500	723,003	769,877	6.5%
84190 - Other Supplies	48,338	49,284	43,000	-12.8%
84200 - Books & Mag. Subscriptions	8,762	11,552	9,205	-20.3%
84300 - Postage	597,459	587,743	608,850	3.6%
84310 - UPS/Fed Express/Courier	2,952	2,058	4,185	103.4%
Total Supplies & Office	1,939,653	2,142,576	2,196,967	2.5%
Travel & Meals				
84510 - Airfare	23,588	21,463	47,950	123.4%
84520 - Mileage	12,362	12,795	15,681	22.6%
84545 - Meals	67,513	68,526	84,230	22.9%
84546 - Meal Allowances	21,223	22,620	21,650	-4.3%
84550 - Lodging	57,462	52,290	84,610	61.8%
84560 - Community Events	12,443	15,929	14,100	-11.5%
84585 - Travel Per Diem	5,323	0	0	N/A
84590 - Other Travel Expense	11,340	10,961	11,825	7.9%
Total Travel & Meals	211,254	204,584	280,046	36.9%

Dakota Electric Association
2019 Budget

Account - Description	2017 Actual	2018 Actual	2019 Budget	% Chg to '18 Actual
Occupancy				
85110 - Building Rent & Lease	6,685	8,317	9,100	9.4%
85120 - Office Electric Sales Tax	11,251	10,656	12,000	12.6%
85130 - Telephone & Cell Phone	156,983	152,351	164,648	8.1%
85140 - Telecommunications-Other	70,542	97,965	136,318	39.1%
85150 - Sewer & Water	26,454	28,266	27,000	-4.5%
85310 - Building Maintenance	63,601	47,386	55,000	16.1%
85320 - Equip Repair & Maintenance	65,136	35,810	38,750	8.2%
Total Occupancy	400,652	380,751	442,816	16.3%
Vehicle Expenses				
82540 - Auto Insurance	65,057	64,696	65,934	1.9%
85410 - Fuel & Oil	253,636	311,064	325,600	4.7%
85420 - Repair Parts	169,101	144,738	169,000	16.8%
85430 - Shop Supplies	54,358	46,404	42,000	-9.5%
85440 - Other Vehicle Exp	31,934	43,236	33,950	-21.5%
85510 - Heavy Vehicle & Trlr Exp Clrd	(284,314)	(358,270)	(401,887)	12.2%
87125 - Depreciation-Vehicles	546,419	644,712	709,348	10.0%
Total Vehicle Expenses	836,191	896,580	943,945	5.3%
Distribution Materials				
86110 - Distribution Mntnce Materials	348,001	323,240	351,598	8.8%
86120 - Distribution Supplies-Tools	171,300	139,344	125,805	-9.7%
86130 - Distribution Supplies-Other	243,561	199,694	214,000	7.2%
86140 - Inventory Count Variance	3,555	8,985	5,000	-44.4%
86160 -Inventory PO Cost Variance	24	(13)	100	-869.2%
86165 -Inventory Obsolescence Write-off	12,000	24,000	24,000	0.0%
86170 -Other Inventory Expense	7,052	7,801	5,000	-35.9%
86210 - Distr Load Control Receivers	42,270	27,278	12,760	-53.2%
86215 - Distr Generation Automation	42,295	23,666	30,000	26.8%
86295 - Distr Equipment Rent & Lease	10,319	7,111	11,300	58.9%
86300 - Distr Maintenance - Other	335,038	355,766	384,484	8.1%
Total Distribution Materials	1,215,415	1,116,872	1,164,047	4.2%
86145 - Burden - Accounting Use Only	(532,657)	(536,965)	(555,295)	3.4%
Total Material Burden/Clearing	(532,657)	(536,965)	(555,295)	3.4%
Miscellaneous				
89010 - Miscellaneous Expense			19,000	N/A
89020 - Bad Debt Expense	80,004	372,996	413,000	10.7%
89025 - Member Relations	42,753	32,388	42,800	32.1%
89030 - Donations	83,498	78,485	78,500	0.0%
89035 - Sponsorships	41,910	48,185	41,250	-14.4%
89040 - Discounts	(5,297)	(5,698)	(5,000)	-12.2%
89050 - Freight	9,855	8,091	11,823	46.1%
89055 - Invoice Cost Variance	(1)	1	0	-100.0%
Total Miscellaneous	252,722	534,448	601,373	12.5%

Dakota Electric Association
2019 Budget

Account - Description	2017 Actual	2018 Actual	2019 Budget	% Chg to '18 Actual
Reimbursements/Transfers				
66005 - Reimbursements	(41,523)	(40,437)	(40,000)	-1.1%
66007 - GRE Reimbursements	(1,416,302)	(1,207,140)	(1,286,212)	6.6%
89901 - Util & Eng Service Trx to COS	(285,195)	(271,377)	(229,664)	-15.4%
89902 - Billable Project Trx to COS	(15,237)	(12,790)	0	-100.0%
Total Reimbursements/Transfers	(1,758,257)	(1,531,744)	(1,555,876)	1.6%
87120 - Depreciation-General Plant	932,678	1,341,590	1,597,317	19.1%
Total Depreciation General Plant	932,678	1,341,590	1,597,317	19.1%
Total Non Labor Expense	**11,713,492**	**12,872,371**	**14,390,141**	**11.8%**
Total Department Expense	**34,105,858**	**36,581,013**	**38,497,188**	**5.2%**
87110 - Deprec-Distribution Plant	8,012,490	8,295,673	8,619,000	3.9%
Total Distribution Depreciation	8,012,490	8,295,673	8,619,000	3.9%
Business Taxes				
87510 - Property & Real Estate Tax	3,608,629	3,371,493	3,700,000	9.7%
87520 - Sales & Use Tax	(1)	0	0	N/A
87530 - Membership Tax	570	790	800	1.3%
Total Business Taxes	3,609,198	3,372,283	3,700,800	9.7%
Interest Expense				
88010 - Interest on LT Debt	3,688,056	3,676,839	4,101,367	11.5%
88020 - Interest on LOC - CFC		470,945	564,600	
88030 - Interest on LOC - CoBank	422,403	38,151		-100.0%
88040 - Interest on Lease Obligation	59,063	64,846	90,383	39.4%
88070 - CFC Mrtg Registration Tax	4,098	4,098	4,092	-0.1%
88090 - Interest Expense - Other	4,166	3,902	4,800	23.0%
88980 - Interest Expense - Intercompany	21,037	36,010	30,000	-16.7%
88990 - RUS Buyout Gain Amort	(109,836)	(76,344)	(47,532)	-37.7%
Total Interest Expense	4,088,987	4,218,447	4,747,710	12.5%
Total Depreciation, Taxes, & Interest	**15,710,675**	**15,886,403**	**17,067,510**	**7.4%**
Total Operating Expenses	**49,816,533**	**52,467,416**	**55,564,698**	**5.9%**
Operating Margin	**3,958,641**	**1,655,367**	**(2,251,083)**	**-236.0%**
Other Income				
91010 - Int Inc-Cnsrvtn Loans&Deposits	434	434	434	0.0%
91030 - Int Inc-DSM Trkr Carrying Cost	51,551	36,892	(9,765)	N/A
91040 - Int Inc-Financial Institutions	137,301	137,402	137,180	-0.2%
92510 - Gain(Loss) Asset Sale	7,578	96,557	18,748	-80.6%
92530 - Gain(Loss) Asset Disposal	(18,544)	(19,530)	0	N/A
66100 - Interco-Subsidiary Earnings	(158,851)	8,227	0	N/A
66040 - Cap Credit Rev - GRE	6,403,850	4,311,432	3,934,030	-8.8%
66041 - Cap Credit Rev - CFC	200,591	209,803	312,108	48.8%
66042 - Cap Credit Rev - Other	150,577	119,277	143,000	19.9%
66043 - Cap Credit Rev - CoBank	410,525	470,700	301,545	-35.9%
Total Other Income	7,185,012	5,371,194	4,837,280	-9.9%
Net Income	**11,143,653**	**7,026,561**	**2,586,197**	**-63.2%**

Workpaper 3
Accounting System Description and Cross-Reference Projects to Form 7 2018

Dakota Electric Association
Accounting System Description and
Cross-Reference Projects to Form 7 2018

Prior to 1997, Dakota Electric utilized an accounting system which was based on the FERC Uniform System of Accounts. Dakota Electric converted to Lawson Software's (now Infor) general ledger system effective January 1997. This system allows the Cooperative to track expenditures in much greater detail since this software has a module to capture expenditures by project code (or activity) in addition to accounts and the system also has the ability to track many cost centers. Instead of implementing the existing FERC Uniform System of Accounts when converting to Lawson, Dakota Electric decided to adopt a new chart of accounts which better categorizes expenditures. The chart of accounts for expenses is shown in the 2019 budget detail in Workpaper 4.

Finance staff creates internal monthly and annual financial reports utilizing the non-FERC chart of accounts which are used by the Board of Directors, management, and cost-center managers. On an annual basis, project codes are mapped to FERC accounts in order to create the Form 7 required by our lender, National Rural Utilities Cooperative Finance Corporation (CFC). The enclosed schedules detail the project codes used by Dakota Electric to track expenses and the FERC account number assigned to each project code to generate the annual Form 7 income statement.

DEA 2018 Form 7 Income Statement (Built from Projects)

FERC Account	Description	Revenue	Cost of Sales	Internal Labor w/o *VSH	*VSH	Payroll Benefits	Reimb & Trsfr to Cost of Sales	All Other Expenses	Other Inc/(Loss)	Income / (Loss)	Summary Income / (Loss)
440	Residential	$ 119,397,406	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 119,397,406**	
441	Irrigation	1,049,852	-	-	-	-	-	-	-	**1,049,852**	
442	Commercial	79,327,445	-	-	-	-	-	-	-	**79,327,445**	
444	Street Lights	2,043,558	-	-	-	-	-	-	-	**2,043,558**	
445	Municipal	3,960	-	-	-	-	-	-	-	**3,960**	
450	Late Charges	743,718	-	-	-	-	-	-	-	**743,718**	
451	Processing Fees & Other Billing Adjustments	416,797	-	-	-	-	-	-	-	**416,797**	
449	DSM Exp & Tax Recovery	155,939	-	-	-	-	-	-	-	**155,939**	
Line 1	**Operating Revenue**	**203,138,675**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**203,138,675**	**$ 203,138,675**
555	**Purchased Power Cost- Line 3**	-	149,330,034	-	-	-	-	-	-	**(149,330,034)**	**(149,330,034)**
580	Operation	-	-	-	-	-	-	-	-	**-**	
581	Load Dispatching	64,808	33,187	902,612	-	597,621	(33,187)	116,050	-	**(1,551,475)**	
582	Station Expense	-	-	373,042	-	179,287	-	142,539	-	**(694,868)**	
583	Overhead Line Expense	-	-	15,571	-	7,774	-	225	-	**(23,570)**	
584	Underground Line Expense	-	-	103,172	-	98,002	-	572,845	-	**(774,019)**	
585	Street Lighting	-	-	-	-	-	-	-	-	**-**	
586	Meter Expense	12,526	7,227	638,846	-	635,104	(1,161)	876,057	-	**(2,143,547)**	
587	Customer Installation	-	-	32,630	-	16,145	-	6,786	-	**(55,561)**	
588	Miscellaneous Distribution	44,562	-	919,696	-	665,557	-	493,453	-	**(2,034,144)**	
589	Rents	-	-	-	-	-	-	-	-	**-**	
Line 6	**Distribution Expense - Operation**	**121,896**	**40,414**	**2,985,569**	**-**	**2,199,490**	**(34,348)**	**2,207,955**	**-**	**(7,277,184)**	**(7,277,184)**
590	Maintenance Supervision & Eng	319,682	268,863	2,164,624	-	1,489,221	(174,802)	800,051	-	**(4,228,275)**	
592	Maintenance of Station Equip	19,320	-	73,519	-	35,194	-	36,776	-	**(126,169)**	
593	Maint of OH Lines (inc tree trimming)	114,529	-	354,967	-	176,937	-	872,417	-	**(1,289,792)**	
594	Maint Underground Lines	-	-	-	-	-	-	-	-	**-**	
595	Maint Line Transformers	-	-	6,667	-	3,238	-	3,000	-	**(12,905)**	
596	Maint Street Light / Signal Sys	-	-	241,868	-	118,044	-	134,285	-	**(494,197)**	
597	Maintenance of Meters	-	-	-	-	-	-	-	-	**-**	
598	Miscellaneous Maint (inc sml auto)	-	-	-	-	-	-	-	-	**-**	
Line 7	**Distribution Expense - Maintenance**	**453,531**	**268,863**	**2,841,645**	**-**	**1,822,634**	**(174,802)**	**1,846,529**	**-**	**(6,151,338)**	**(6,151,338)**
902	Meter Reading	-	-	392,032	-	193,756	-	287,067	-	**(872,855)**	
903	Customer Records & Collections	-	-	1,721,119	-	996,992	-	1,348,993	-	**(4,067,104)**	
904	Uncollectible Accounts	-	-	-	-	-	-	372,996	-	**(372,996)**	
Line 8	**Consumer Accounts Expense**	**-**	**-**	**2,113,151**	**-**	**1,190,748**	**-**	**2,009,056**	**-**	**(5,312,955)**	**(5,312,955)**
907	Supervision	-	-	-	-	-	-	-	-	**-**	
908	Customer Assistance & DSM Programs	-	-	699,002	-	465,620	(1,190,732)	2,393,097	-	**(2,366,987)**	
909	Info,Advertising,&Instr (inc Circuits & MAC)	24,300	12,790	173,079	-	128,808	(29,221)	660,912	-	**(922,068)**	
910	Economic Development	-	-	129,384	-	84,604	-	82,717	-	**(296,705)**	
Line 9	**Customer Service & Info Expense**	**24,300**	**12,790**	**1,001,465**	**-**	**679,032**	**(1,219,953)**	**3,136,726**	**-**	**(3,585,760)**	**(3,585,760)**
920	Admin & General (inc vehicles)	-	-	4,888,395	2,223,364	5,832	-	151	-	**(7,117,742)**	
921	Office Supplies, Postage & Software	51,465	48,900	-	-	-	(47,379)	1,475,321	-	**(1,425,377)**	
923	Outside services employed.	-	-	-	-	-	-	476,314	-	**(476,314)**	
924	Property Insurance	-	-	-	-	-	-	73,875	-	**(73,875)**	
925	Injuries and damages	-	-	4,940	-	2,432	-	(3,871)	-	**(3,501)**	
926	Employee Benefits & Education	-	-	-	-	1,694,587	-	-	-	**(1,694,587)**	
927	Franchise Requirements	-	-	-	-	-	-	-	-	**-**	
928	Regulatory Commission Expense	-	-	-	-	-	-	426,961	-	**(426,961)**	
930	Misc General Exp	-	-	-	-	-	-	-	-	**-**	
930.2	Misc General Exp - Annual Mtg, Directors Fees	-	-	-	-	-	-	689,481	-	**(689,481)**	
935	Maintenance Office Bldg & Equip	-	-	-	-	-	-	-	-	**-**	
Line 11	**Administrative & General Expense**	**51,465**	**48,900**	**4,893,335**	**2,223,364**	**1,702,851**	**(47,379)**	**3,138,232**	**-**	**(11,907,838)**	**(11,907,838)**
Line 12	**Total Operation & Maintenance Ln2-10**	**651,192**	**149,701,001**	**13,835,165**	**2,223,364**	**7,594,755**	**(1,476,482)**	**12,338,498**	**-**	**(183,565,109)**	**(183,565,109)**
403	Depreciation & Amort - Line 13	-	-	-	-	-	-	10,281,975	-	**(10,281,975)**	**(10,281,975)**

FERC Account	Description	Revenue	Cost of Sales	Internal Labor w/o *VSH	*VSH	Payroll Benefits	Reimb & Trsfr to Cost of Sales	All Other Expenses	Other Inc/(Loss)	Income / (Loss)		Summary Income / (Loss)
408	Property & Other Taxes - Line 14	-	-	-	-	-	-	3,372,283	-	**(3,372,283)**		**(3,372,283)**
427	Interest on Long Term Debt - Line 16	-	-	-	-	-	-	3,741,685	-	**(3,741,685)**		**(3,741,685)**
431	Interest Expense - Other - Line 18	-	-	-	-	-	-	549,008	-	**(549,008)**		**(549,008)**
426	Other Deductions - Ln 19 Donations	-	-	-	-	-	-	78,485	-	**(78,485)**	**A**	**(78,485)**
428	Amortization of Debt Discount & Exp - Line 19	-	-	-	-	-	-	(76,344)	-	**76,344**	**A**	**76,344**
429	Other Deductions - conversion fees - Line 19	-	-	-	-	-	-	4,098	-	**(4,098)**	**A**	**(4,098)**
Line 20	**Total Cost of Service**	**651,192**	**149,701,001**	**13,835,165**	**2,223,364**	**7,594,755**	**(1,476,482)**	**30,289,688**	**-**	**(201,516,299)**		**(201,516,299)**
Line 21	**Patronage Capital & Operating Margins**	**203,789,867**	**149,701,001**	**13,835,165**	**2,223,364**	**7,594,755**	**(1,476,482)**	**30,289,688**	**-**	**1,622,376**		**1,622,376**
419	Interest Income - Line 22 (Non-op Margins)	-	-	-	-	-	-	-	174,728	**174,728**		**174,728**
418	Subsidiary Earnings - Line 24	-	-	-	-	-	-	-	8,227	**8,227**		**8,227**
415	Other Deductions - Ln 25 Revenue from Merchandising, Jobbing & Contract Work	241,509	207,590	38,652	-	16,708	(55,262)	825	-	**32,996**	**B**	**32,996**
416	Other Deductions - Ln 25 Expenses from Merchandising, Jobbing & Contract Work	-	-	-	-	-	-	-	-	**-**	**B**	**-**
421	Other Deductions - Ln 25 Gain (Loss) on Asset Sale	-	-	-	-	-	-	-	77,027	**77,027**	**B**	**77,027**
423	G&T Capital Credits - Line 26	-	-	-	-	-	-	-	4,311,432	**4,311,432**	**C**	**4,311,432**
424	CFC & Other Capital Credits Line 27	-	-	-	-	-	-	-	799,780	**799,780**	**C**	**799,780**
Line 29	**Net Margins**	**$ 204,031,376**	**$ 149,908,591**	**$ 13,873,817**	**$ 2,223,364**	**$ 7,611,463**	**$ (1,531,744)**	**$ 30,290,513**	**$ 5,371,194**	**$ 7,026,566**		**$ 7,026,566**

Dakota Electric Association (Co#100)
2018

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
65020	449	184,126	-	-	-	-	-	-	-	184,126
65030	449	(28,187)	-	-	-	-	-	-	-	(28,187)
66040	423	-	-	-	-	-	-	-	4,311,432	4,311,432
66041	424	-	-	-	-	-	-	-	209,803	209,803
66042	424	-	-	-	-	-	-	-	119,277	119,277
66043	424	-	-	-	-	-	-	-	470,700	470,700
66100	418	-	-	-	-	-	-	-	8,227	8,227
70000s	555	-	149,330,034	-	-	-	-	-	-	(149,330,034)
62000s	444	2,043,558	-	-	-	-	-	-	-	2,043,558
63040-63999	440	119,397,406	-	-	-	-	-	-	-	119,397,406
63047	445	3,960	-	-	-	-	-	-	-	3,960
63036-63037	441	1,049,852	-	-	-	-	-	-	-	1,049,852
64000s	442	79,327,445	-	-	-	-	-	-	-	79,327,445
65510-65515	450	743,718	-	-	-	-	-	-	-	743,718
65520-65999	451	424,224	-	-	-	-	-	-	-	424,224
66020	451	(7,427)	-	-	-	-	-	-	-	(7,427)
91010	419	-	-	-	-	-	-	-	434	434
91030	419	-	-	-	-	-	-	-	36,892	36,892
91040	419	-	-	-	-	-	-	-	137,402	137,402
88010	427	-	-	-	-	-	-	3,676,839	-	(3,676,839)
88040	427	-	-	-	-	-	-	64,846	-	(64,846)
88070	429	-	-	-	-	-	-	4,098	-	(4,098)
88030	431	-	-	-	-	-	-	38,151	-	(38,151)
88090 & 980	431	-	-	-	-	-	-	510,857	-	(510,857)
88990	428	-	-	-	-	-	-	(76,344)	-	76,344
87110	403	-	-	-	-	-	-	8,295,673	-	(8,295,673)
87510-30	408	-	-	-	-	-	-	3,372,283	-	(3,372,283)
87120	403	-	-	-	-	-	-	1,341,590	-	(1,341,590)
87125	403	-	-	-	-	-	-	644,712	-	(644,712)
89030	426	-	-	-	-	-	-	78,485	-	(78,485)
COR	920	-	-	(8,191)	2,223,364	-	-	-	-	(2,215,173)
COR	921	-	8,255	-	-	-	-	10,691	-	(18,946)
COR	923	-	-	-	-	-	-	90	-	(90)
COR	924	-	-	-	-	-	-	73,875	-	(73,875)
COR	926	-	-	-	-	(1,984,336)	-	-	-	1,984,336
70CELL	581	-	-	1,609	-	804	-	-	-	(2,413)
ACTSAF	920	-	-	15,206	-	-	-	-	-	(15,206)
ACTSAF	921	-	-	-	-	-	-	994	-	(994)
ACTSAF	923	-	-	-	-	-	-	2,601	-	(2,601)
ACTSAF	926	-	-	-	-	7,603	-	-	-	(7,603)
ACTUNEUP	908	-	-	1,605	-	799	(4,475)	5,200	-	(3,129)
ACS	920	-	-	194,397	-	-	-	-	-	(194,397)
ACS	921	-	-	-	-	-	(1)	34,533	-	(34,533)
ACS	926	-	-	-	-	145,275	-	-	-	(145,275)
AEN	920	-	-	195,490	-	-	-	-	-	(195,490)
AEN	921	-	-	-	-	-	-	36,444	-	(36,444)
AEN	926	-	-	-	-	174,360	-	-	-	(174,360)
AERT	590	-	-	107,403	-	52,957	-	(67,258)	-	(93,102)
AERT	421	-	-	-	-	-	-	-	(2,329)	(2,329)
AFS	920	-	-	242,426	-	-	-	-	-	(242,426)
AFS	921	-	-	-	-	-	-	24,182	-	(24,182)
AFS	926	-	-	-	-	181,935	-	-	-	(181,935)
AGI	586	-	-	-	-	-	-	18	-	(18)
AGI2017	586	-	-	5,635	-	2,817	-	-	-	(8,452)
AGI2018	586	-	-	214,196	-	107,099	-	382,291	-	(703,586)
AGIADMIN	921	-	-	-	-	-	-	218	-	(218)
AGIADMIN	923	-	-	-	-	-	-	6,192	-	(6,192)
AGILDMGMT	581	-	-	144	-	72	-	14,043	-	(14,259)
AGIMTRROOM	586	-	-	-	-	-	-	2,473	-	(2,473)
AGINETSEC	586	-	-	-	-	-	-	11,018	-	(11,018)
AGISOFTWARE	586	-	-	-	-	-	-	174,898	-	(174,898)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
AGSS2016	586	-	-	50	-	25	-	-	-	(75)
AMRTURT	586	-	-	17,334	-	8,640	-	40,680	-	(66,654)
AMS	920	-	-	328,283	-	-	-	-	-	(328,283)
AMS	921	-	-	-	-	-	-	283,259	-	(283,259)
AMS	923	-	-	-	-	-	-	46,183	-	(46,183)
AMS	926	-	-	-	-	199,573	-	-	-	(199,573)
ANMTG	920	-	-	4,618	-	-	-	-	-	(4,618)
ANMTG	930.2	-	-	-	-	-	-	7,835	-	(7,835)
ANMTG	926	-	-	-	-	2,155	-	-	-	(2,155)
APAY	920	-	-	61,131	-	-	-	-	-	(61,131)
APAY	921	-	-	-	-	-	-	4,101	-	(4,101)
APAY	923	-	-	-	-	-	-	3,191	-	(3,191)
APAY	926	-	-	-	-	30,545	-	-	-	(30,545)
ASSET	920	-	-	21,010	-	-	-	-	-	(21,010)
ASSET	926	-	-	-	-	10,505	-	-	-	(10,505)
AUDC	908	-	-	3,234	-	1,617	-	790	-	(5,642)
AUDLOW	908	-	-	96	-	48	-	6,533	-	(6,677)
AUDR	908	-	-	10,927	-	5,464	-	3,501	-	(19,892)
AUO	920	-	-	212,980	-	-	-	-	-	(212,980)
AUO	921	-	-	-	-	-	-	17,630	-	(17,630)
AUO	926	-	-	-	-	157,718	-	-	-	(157,718)
AVGRERTU	415	3,965	2,674	1,783	-	891	(2,674)	-	-	1,291
BARCODE	920	-	-	6,563	-	-	-	-	-	(6,563)
BARCODE	921	-	-	-	-	-	-	828	-	(828)
BARCODE	926	-	-	-	-	3,281	-	-	-	(3,281)
BENE	920	-	-	2,123	-	-	-	-	-	(2,123)
BENE	921	232	-	-	-	-	-	3,950	-	(3,718)
BENE	923	-	-	-	-	-	-	2,250	-	(2,250)
BENE	926	-	-	-	-	144,650	-	-	-	(144,650)
BILL	903	-	-	179,679	-	87,971	-	734,932	-	(1,002,582)
BILLNON	903	-	-	34,910	-	17,418	-	-	-	(52,328)
BLD	920	-	-	202,239	-	-	-	-	-	(202,239)
BLD	921	-	-	-	-	-	-	115,179	-	(115,179)
BLD	923	-	-	-	-	-	-	127,029	-	(127,029)
BLD	926	-	-	-	-	132,096	-	-	-	(132,096)
BLDEQUIP	920	-	-	531	-	-	-	-	-	(531)
BLDEQUIP	926	-	-	-	-	265	-	-	-	(265)
BLDELEC	920	-	-	1,126	-	-	-	-	-	(1,126)
BLDELEC	921	-	-	-	-	-	-	2,506	-	(2,506)
BLDELEC	926	-	-	-	-	563	-	-	-	(563)
BLDROOF	920	-	-	840	-	-	-	-	-	(840)
BLDROOF	926	-	-	-	-	420	-	-	-	(420)
BOD	920	-	-	118,357	-	-	-	-	-	(118,357)
BOD	921	-	-	-	-	-	(100)	-	-	100
BOD	926	-	-	-	-	59,179	-	-	-	(59,179)
BOD	930.2	-	-	-	-	-	-	35,855	-	(35,855)
BOD-Directors	930.2	-	-	-	-	-	-	419,223	-	(419,223)
BODELECT	920	-	-	3,222	-	-	-	-	-	(3,222)
BODELECT	926	-	-	-	-	1,611	-	-	-	(1,611)
BODELECT	930.2	-	-	-	-	-	-	116,137	-	(116,137)
BRANDING	920	-	-	3,173	-	-	-	-	-	(3,173)
BRANDING	921	-	-	-	-	-	-	115,225	-	(115,225)
BRANDING	926	-	-	-	-	1,586	-	-	-	(1,586)
BUDGET	920	-	-	67,826	-	-	-	-	-	(67,826)
BUDGET	921	-	-	-	-	-	-	54	-	(54)
BUDGET	926	-	-	-	-	33,913	-	-	-	(33,913)
BVGREUFLS	415	20,872	13,269	8,397	-	4,069	(12,466)	-	-	7,603
CACCI	908	-	-	2,917	-	1,458	-	930	-	(5,305)
CACRES	908	-	-	33,127	-	16,337	(5,500)	78,214	-	(122,178)
CACRES	415	-	116	-	-	-	-	-	-	(116)
CAPACIT	583	-	-	15,571	-	7,774	-	225	-	(23,570)
CAPCR	920	-	-	56,989	-	-	-	-	-	(56,989)
CAPCR	926	-	-	-	-	28,420	-	-	-	(28,420)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
CAPCR	930.2	-	-	-	-	-	-	42,288	-	(42,288)
CARS	920	-	-	4,203	-	-	-	-	-	(4,203)
CARS	921	-	-	-	-	-	(17,885)	(5,936)	-	23,822
CARS	926	-	-	-	-	2,094	-	-	-	(2,094)
CARS	421	-	-	-	-	-	-	-	4,865	4,865
CASH	903	-	-	119,168	-	51,165	-	71,628	-	(241,961)
CFLRES	908	-	-	26	-	13	(48)	48	-	(39)
CIPDIGITAL	909	-	-	-	-	-	-	35,842	-	(35,842)
CIPGOALS	908	-	-	68,959	-	34,438	-	99	-	(103,497)
CIGRANT	908	-	-	66,279	-	33,136	(728,244)	961,287	-	(332,458)
CIGROUP	908	-	-	8,288	-	4,144	-	2,003	-	(14,434)
CIPNEWS	909	-	-	-	-	-	-	10,009	-	(10,009)
CIPTV	909	-	-	-	-	-	-	63,625	-	(63,625)
CINEWS	909	-	-	106	-	53	-	2,807	-	(2,967)
CIRC	909	24,300	12,790	27,332	-	13,666	(12,790)	372,494	-	(389,193)
CIRC2018	909	-	-	5,489	-	2,744	-	22,089	-	(30,322)
CIS	903	-	-	23,280	-	11,640	-	81,872	-	(116,792)
CISBIL	903	-	-	42,628	-	21,314	-	64,249	-	(128,191)
CISIMP	903	-	-	283,825	-	139,631	-	122,255	-	(545,711)
COLLCTEXP	903	-	-	130,976	-	62,568	-	3,997	-	(197,540)
COLLRCY	903	-	-	3,178	-	1,589	-	13,685	-	(18,451)
COMMREL	920	-	-	73,688	-	-	-	-	-	(73,688)
COMMREL	930.2	-	-	-	-	-	-	61,296	-	(61,296)
COMMREL	926	-	-	-	-	36,786	-	-	-	(36,786)
COMPPLAN	920	-	-	60	-	-	-	-	-	(60)
COMPPLAN	923	-	-	-	-	-	-	4,589	-	(4,589)
COMPPLAN	926	-	-	-	-	30	-	-	-	(30)
CRADIO2018	588	-	-	533	-	267	-	-	-	(800)
CREWCALL	581	-	-	-	-	-	-	2,004	-	(2,004)
CUS	903	-	-	743,793	-	525,332	-	71,116	-	(1,340,241)
CUSEVENT	920	-	-	5,365	-	-	-	-	-	(5,365)
CUSEVENT	921	-	-	-	-	-	-	36,208	-	(36,208)
CUSEVENT	923	-	-	-	-	-	-	1,400	-	(1,400)
CUSEVENT	926	-	-	-	-	2,094	-	-	-	(2,094)
CWPLAN	920	-	-	1,656	-	-	-	-	-	(1,656)
CWPLAN	926	-	-	-	-	828	-	-	-	(828)
CYBERCOMM	920	-	-	175	-	-	-	-	-	(175)
CYBERCOMM	926	-	-	-	-	88	-	-	-	(88)
DEAEAS	920	-	-	1,433	-	-	-	-	-	(1,433)
DEAEAS	921	2,348	-	-	-	-	-	-	-	2,348
DEAEAS	926	-	-	-	-	716	-	-	-	(716)
DEAGEN	920	-	-	2,361	-	-	-	-	-	(2,361)
DEAGEN	921	3,781	-	-	-	-	-	-	-	3,781
DEAGEN	926	-	-	-	-	1,181	-	-	-	(1,181)
DEALRPLAN	920	-	-	286	-	-	-	-	-	(286)
DEALRPLAN	923	-	-	-	-	-	-	1,530	-	(1,530)
DEALRPLAN	926	-	-	-	-	143	-	-	-	(143)
DECLINEHEALTH	926	-	-	-	-	58,860	-	-	-	(58,860)
DEHUMID	908	-	-	804	-	402	(6,025)	7,017	-	(2,198)
DGHASTING	592	8,556	-	-	-	-	-	-	-	8,556
DGLMARION	592	10,764	-	-	-	-	-	-	-	10,764
DIGITAL	910	-	-	-	-	-	-	5,788	-	(5,788)
DIGR	590	-	-	31,322	-	15,379	-	(8,439)	-	(38,262)
DIS	581	-	-	261,225	-	279,083	-	32,769	-	(573,076)
DISOUT	581	-	-	344,014	-	170,622	-	-	-	(514,636)
DISSWITCH	581	-	-	195,024	-	97,512	-	-	-	(292,536)
DODDGRERTU	415	3,258	2,140	1,427	-	713	(2,140)	-	-	1,118
DONCOMM	920	-	-	2,038	-	1,019	-	-	-	(3,057)
DONHUMSV	920	-	-	1,949	-	974	-	-	-	(2,923)
DONLABOR	920	-	-	5,376	-	2,688	-	-	-	(8,064)
DONYOUTH	920	-	-	2,065	-	1,032	-	-	-	(3,097)
DSM	908	-	-	90,755	-	116,673	-	19,152	-	(226,580)
E3TRAIN	908	-	-	5,297	-	2,649	-	3,710	-	(11,656)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
EBILL	903	-	-	8,716	-	4,358	-	182,135	-	(195,208)
ECMMOTOR	908	-	-	7,760	-	3,864	(76,600)	91,500	-	(26,524)
ECO	910	-	-	111,217	-	75,991	-	35,205	-	(222,413)
EDU	920	-	-	255,978	-	-	-	-	-	(255,978)
EDU	921	-	-	-	-	-	-	80,066	-	(80,066)
EDU	926	-	-	-	-	127,460	-	-	-	(127,460)
EDUD	908	-	-	1,081	-	540	-	-	-	(1,621)
EFUNC	920	-	-	9,363	-	-	-	-	-	(9,363)
EFUNC	921	-	-	-	-	-	-	18,427	-	(18,427)
EFUNC	926	-	-	-	-	4,524	-	-	-	(4,524)
EIL	908	-	-	17,270	-	8,635	-	73,506	-	(99,411)
EILPROD	908	-	-	22,022	-	11,011	-	4,229	-	(37,262)
ELECCAR	908	-	-	28,916	-	14,458	(27,507)	57,231	-	(73,098)
ELECCAR	415	7,825	6,486	-	-	-	-	-	-	1,339
ELECHEAT	908	-	-	6,552	-	3,276	-	3,881	-	(13,708)
ELECHEAT	415	4,108	4,651	-	-	-	-	-	-	(543)
ENS	920	-	-	70,806	-	-	-	-	-	(70,806)
ENS	926	-	-	-	-	35,299	-	-	-	(35,299)
ENVIRON	908	-	-	179	-	90	-	2,400	-	(2,669)
ESDRYER	908	-	-	510	-	255	(6,650)	6,950	-	(1,065)
ETS	588	-	-	323,421	-	216,801	-	76,825	-	(617,046)
FAIRSHOW	908	-	-	7,374	-	3,230	-	9,751	-	(20,355)
FIBERNETWK	588	-	-	152	-	76	-	-	-	(228)
FIN	920	-	-	45,826	(0)	-	-	-	-	(45,826)
FIN	921	-	-	-	-	-	-	9,923	-	(9,923)
FIN	923	-	-	-	-	-	-	36,729	-	(36,729)
FIN	926	-	-	-	-	125,812	-	-	-	(125,812)
FINAL	920	-	-	3,848	-	-	-	-	-	(3,848)
FINAL	926	-	-	-	-	1,924	-	-	-	(1,924)
FLOORING	920	-	-	410	-	-	-	-	-	(410)
FLOORING	921	-	-	-	-	-	-	957	-	(957)
FLOORING	926	-	-	-	-	205	-	-	-	(205)
FRANAV	920	-	-	161	-	-	-	-	-	(161)
FRANAV	926	-	-	-	-	80	-	-	-	(80)
FRANBV	920	-	-	161	-	-	-	-	-	(161)
FRANBV	926	-	-	-	-	80	-	-	-	(80)
FRANHA	920	-	-	79	-	-	-	-	-	(79)
FRANHA	926	-	-	-	-	40	-	-	-	(40)
FRANIGH	920	-	-	89	-	-	-	-	-	(89)
FRANIGH	926	-	-	-	-	45	-	-	-	(45)
FRECYCLE	908	-	-	-	-	-	-	15,884	-	(15,884)
FREEDOMSERV	926	-	-	-	-	204,870	-	-	-	(204,870)
FREEZER	908	-	-	111	-	56	(1,200)	1,500	-	(467)
GENEVAL	588	5,300	-	34,128	-	17,064	-	-	-	(45,892)
GENMT	587	-	-	31,739	-	15,699	-	6,634	-	(54,072)
GENMTDEA	921	-	-	-	-	-	-	5,288	-	(5,288)
GIS	588	-	-	169	-	85	-	-	-	(254)
GISMNT	588	-	-	-	-	-	-	184,683	-	(184,683)
GPUMPRES	908	-	-	511	-	256	(6,000)	6,241	-	(1,008)
GSOC	584	-	-	-	-	-	-	43,535	-	(43,535)
HAZARD	593	-	-	2,059	-	1,030	-	23,317	-	(26,406)
HELP	920	-	-	236	-	118	-	152	-	(505)
HIEFF	908	-	-	12,290	-	6,141	(39,050)	312,020	-	(291,401)
HIRE	920	-	-	53,129	-	-	-	-	-	(53,129)
HIRE	921	-	-	-	-	-	-	80,360	-	(80,360)
HIRE	926	-	-	-	-	26,565	-	-	-	(26,565)
HLPDSK	920	-	-	148,456	-	-	-	-	-	(148,456)
HLPDSK	926	-	-	-	-	74,228	-	-	-	(74,228)
HPUMP	908	-	-	6,801	-	3,401	(153,830)	170,912	-	(27,284)
HPUMP	415	1,580	1,012	-	-	-	-	-	-	568
HPWH	908	-	-	-	-	-	(500)	1,500	-	(1,000)
HRP	920	-	-	221,446	-	-	-	-	-	(221,446)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
HRP	921	-	-	-	-	-	(513)	37,980	-	(37,466)
HRP	923	-	-	-	-	-	-	9,823	-	(9,823)
HRP	926	-	-	-	-	152,332	-	-	-	(152,332)
HUBBUSHING	587	-	-	96	-	48	-	152	-	(296)
HVACHP	920	-	-	51	-	-	-	-	-	(51)
HVACHP	926	-	-	-	-	26	-	-	-	(26)
HVACHP	421	-	-	-	-	-	-	-	(2,911)	(2,911)
IFS	920	-	-	766,517	-	-	-	-	-	(766,517)
IFS	921	-	-	-	-	-	-	635,982	-	(635,982)
IFS	923	-	-	-	-	-	-	60,950	-	(60,950)
IFS	926	-	-	-	-	561,446	-	-	-	(561,446)
IFS	421	-	-	-	-	-	-	-	50	50
IMAGE	920	-	-	10,916	-	-	-	-	-	(10,916)
IMAGE	926	-	-	-	-	5,458	-	-	-	(5,458)
INCELIGIBL	908	-	-	404	-	202	(15,854)	89,490	-	(74,241)
INSC	925	-	-	719	-	321	-	2,446	-	(3,487)
INTERNET17	921	-	-	-	-	-	-	6,007	-	(6,007)
INTERNET17	923	-	-	-	-	-	-	2,489	-	(2,489)
IRRIG	908	-	-	14,734	-	7,367	-	857	-	(22,958)
ISSTEER	920	-	-	2,022	-	-	-	-	-	(2,022)
ISSTEER	921	-	-	-	-	-	-	364	-	(364)
ISSTEER	926	-	-	-	-	1,011	-	-	-	(1,011)
JTUSE	593	114,529	-	-	-	-	-	435	-	114,095
KEY	908	-	-	182,571	-	136,890	-	24,877	-	(344,339)
KIDSAFE	910	-	-	114	-	57	-	2,462	-	(2,633)
KORTERRA	581	-	-	-	-	-	-	29,925	-	(29,925)
LAWSON	920	-	-	79,834	-	-	-	-	-	(79,834)
LAWSON	921	-	-	-	-	-	-	90,867	-	(90,867)
LAWSON	923	-	-	-	-	-	-	2,798	-	(2,798)
LAWSON	926	-	-	-	-	39,917	-	-	-	(39,917)
LEDLIGHTS	908	-	-	16,027	(0)	8,001	(33,588)	45,381	-	(35,822)
LEDXMAS	908	-	-	65	-	33	(1,597)	1,599	-	(100)
LEDYARD	908	-	-	20	-	10	(120)	120	-	(29)
LEGIS	920	-	-	3,008	-	-	-	-	-	(3,008)
LEGIS	921	-	-	-	-	-	-	110	-	(110)
LEGIS	926	-	-	-	-	1,504	-	-	-	(1,504)
LIACMAINT	908	-	-	-	-	-	-	7,267	-	(7,267)
LIAIRCON	908	-	-	-	-	-	-	14,536	-	(14,536)
LICLSWSHR	908	-	-	-	-	-	(9,400)	9,772	-	(372)
LIDEHUMID	908	-	-	-	-	-	-	1,050	-	(1,050)
LIDISH	908	-	-	-	-	-	-	11,418	-	(11,418)
LIFREEZER	908	-	-	-	-	-	-	10,256	-	(10,256)
LIMICRO	908	-	-	-	-	-	-	7,326	-	(7,326)
LIROOMAC	908	-	-	-	-	-	-	936	-	(936)
LOADCTRL	581	-	-	61,967	-	30,214	-	37,310	-	(129,491)
LOADCTRL	415	-	162	-	-	-	-	-	-	(162)
LOBBYTECH	921	-	-	-	-	-	-	846	-	(846)
LOBBYTECH	923	-	-	-	-	-	-	337	-	(337)
LOC	584	-	-	71,685	-	82,266	-	456,875	-	(610,826)
MACT	920	-	-	133,520	-	-	-	-	-	(133,520)
MACT	926	-	-	-	-	66,760	-	-	-	(66,760)
MAI	590	-	-	1,391,606	-	535,135	-	198,612	-	(2,125,353)
MAPCHECK	588	-	-	17,392	-	8,696	-	-	-	(26,089)
MAPPROJ	588	-	-	7,793	-	3,897	-	-	-	(11,690)
MAPUPDATE	588	-	-	15,335	-	145	-	-	-	(15,480)
MAT	920	-	-	289,785	-	-	-	-	-	(289,785)
MAT	921	7,410	7,771	-	-	-	-	(493,981)	-	493,620
MAT	923	-	-	-	-	-	-	176	-	(176)
MAT	926	-	-	-	-	210,172	-	-	-	(210,172)
MECHS	920	-	-	4,452	-	-	-	-	-	(4,452)
MECHS	921	37,693	32,874	-	-	-	(7,005)	3,518	-	8,306
MECHS	926	-	-	-	-	2,226	-	-	-	(2,226)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
MET	586	-	-	70,852	-	242,650	(39)	126,692	-	(440,155)
MET	904	-	-	-	-	-	-	372,996	-	(372,996)
METERMIXUP	586	-	-	174	-	87	-	-	-	(261)
METRD	902	-	-	392,032	-	193,756	-	287,067	-	(872,856)
MILSOFT	588	-	-	-	-	-	-	9,838	-	(9,838)
MKT	909	-	-	131,314	-	107,924	(23)	51,093	-	(290,309)
MKTPLAN	910	-	-	12,314	-	6,149	-	1,762	-	(20,224)
MKTRES	910	-	-	41	-	21	-	-	-	(62)
MLT	586	10,181	6,054	272,883	-	245,627	-	111,027	-	(625,409)
MLTREV	586	2,345	1,173	1,018	-	103	(1,121)	-	-	1,172
MONITOR	581	40,500	17,554	11,703	-	5,851	(17,554)	-	-	22,946
MTRTSTCI	586	-	-	15,095	-	7,548	-	13,480	-	(36,123)
MTRTSTRES	586	-	-	13,205	-	6,602	-	13,480	-	(33,287)
MULTDWEL	586	-	-	3,853	-	1,926	-	-	-	(5,779)
MVECEDARLK	415	2,392	1,670	1,113	-	557	(1,670)	-	-	722
MVZINRAN	415	54,386	34,898	24,762	-	9,893	(34,655)	-	-	19,488
NCD	588	-	-	253,565	-	258,839	-	71,661	-	(584,065)
NCEEP	909	-	-	-	-	-	(16,408)	55,150	-	(38,742)
NETTECH	908	-	-	1,350	-	675	-	1,895	-	(3,920)
OFFSERV	920	-	-	4,397	-	-	-	-	-	(4,397)
OFFSERV	921	-	-	-	-	-	-	19,451	-	(19,451)
OFFSERV	923	-	-	-	-	-	-	1,754	-	(1,754)
OFFSERV	926	-	-	-	-	2,161	-	-	-	(2,161)
OHTRAN	595	-	-	6,667	-	3,238	-	3,000	-	(12,905)
OHTTR	593	-	-	336,158	-	167,532	-	844,757	-	(1,348,447)
OILSPILL	588	-	-	1,707	-	704	-	56	-	(2,467)
OUTAGECOMM	908	-	-	65	-	33	-	36,067	-	(36,165)
PAINT	920	-	-	154	-	-	-	-	-	(154)
PAINT	926	-	-	-	-	77	-	-	-	(77)
PAY	920	-	-	56,922	-	-	-	-	-	(56,922)
PAY	921	-	-	-	-	-	-	2,715	-	(2,715)
PAY	923	-	-	-	-	-	-	19,453	-	(19,453)
PAY	926	-	-	-	-	28,407	-	-	-	(28,407)
PCBTEST	582	-	-	459	-	230	-	1,820	-	(2,509)
PEAK	908	-	-	4,033	-	2,016	-	196	-	(6,245)
PERRES	910	-	-	1,304	-	652	-	19,420	-	(21,376)
PHONE	920	-	-	22,832	-	-	-	-	-	(22,832)
PHONE	921	-	-	-	-	-	-	86,239	-	(86,239)
PHONE	923	-	-	-	-	-	-	1,426	-	(1,426)
PHONE	926	-	-	-	-	11,416	-	-	-	(11,416)
PICK	920	-	-	19,943	-	-	-	-	-	(19,943)
PICK	921	-	-	-	-	-	(9,659)	(103,193)	-	112,852
PICK	923	-	-	-	-	-	-	45	-	(45)
PICK	926	-	-	-	-	9,809	-	-	-	(9,809)
PICK	421	-	-	-	-	-	-	-	644	644
PII	920	-	-	1,955	-	-	-	-	-	(1,955)
PII	926	-	-	-	-	978	-	-	-	(978)
PLCMASTER	582	-	-	-	-	-	-	40,886	-	(40,886)
PMHSPRING	590	-	-	1,072	-	536	-	-	-	(1,608)
POLEYDMTNC	920	-	-	2,175	-	-	-	-	-	(2,175)
POLEYDMTNC	921	-	-	-	-	-	-	1,071	-	(1,071)
POLEYDMTNC	926	-	-	-	-	1,088	-	-	-	(1,088)
POOLHEAT	908	-	-	-	-	-	(800)	800	-	-
POOLPUMP	908	-	-	33	-	16	(5,000)	6,400	-	(1,449)
PORCHEMNT	588	-	-	-	-	-	-	9,744	-	(9,744)
POSTING	588	-	-	18,621	-	9,311	-	-	-	(27,932)
POWR	590	-	-	32,461	-	15,820	-	118,247	-	(166,528)
POWR	421	-	-	-	-	-	-	-	85,357	85,357
POWSUP	920	-	-	74,266	-	-	-	-	-	(74,266)
POWSUP	921	-	-	-	-	-	-	694	-	(694)
POWSUP	923	-	-	-	-	-	-	2,398	-	(2,398)
POWSUP	926	-	-	-	-	37,133	-	-	-	(37,133)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
PQA	587	-	-	795	-	398	-	-	-	(1,193)
PUBREL	920	-	-	61,966	-	-	-	-	-	(61,966)
PUBREL	921	-	-	-	-	-	-	2,152	-	(2,152)
PUBREL	923	-	-	-	-	-	-	1,297	-	(1,297)
PUBREL	926	-	-	-	-	30,983	-	-	-	(30,983)
PUR	920	-	-	133,752	-	-	-	-	-	(133,752)
PUR	921	-	-	-	-	-	-	26,999	-	(26,999)
PUR	923	-	-	-	-	-	-	683	-	(683)
PUR	926	-	-	-	-	92,027	-	-	-	(92,027)
RASTER	588	-	-	6,449	-	3,224	-	84	-	(9,758)
RECLOSERS	593	-	-	14,813	-	7,407	-	3,862	-	(26,082)
REDFLAG	928	-	-	-	-	-	-	11,196	-	(11,196)
REFRIGLOW	908	-	-	-	-	-	-	28,675	-	(28,675)
REG	920	-	-	55,405	-	-	-	-	-	(55,405)
REG	921	-	-	-	-	-	-	5,157	-	(5,157)
REG	926	-	-	-	-	27,703	-	-	-	(27,703)
REG	928	-	-	-	-	-	-	281,462	-	(281,462)
REGD	920	-	-	488	-	-	-	-	-	(488)
REGD	926	-	-	-	-	244	-	-	-	(244)
REGD	928	-	-	-	-	-	-	134,303	-	(134,303)
REGENGINEER	588	-	-	32,186	-	16,093	-	368	-	(48,647)
REGIDP	588	-	-	1,031	-	516	-	1,008	-	(2,554)
REGSRSQ	920	-	-	391	-	-	-	-	-	(391)
REGSRSQ	926	-	-	-	-	196	-	-	-	(196)
REGULAT	593	-	-	1,937	-	968	-	47	-	(2,952)
RENEW	908	-	-	1,507	-	750	-	2,086	-	(4,343)
RFGRCYC	908	-	-	4,070	-	2,031	(31,200)	41,250	-	(16,150)
ROOMSTORG	908	-	-	107	-	53	(3,720)	5,109	-	(1,549)
ROW	588	39,262	-	96,953	-	48,477	-	6,840	-	(113,008)
SAF	920	-	-	161,183	-	-	-	-	-	(161,183)
SAF	921	-	-	-	-	-	-	197,396	-	(197,396)
SAF	923	-	-	-	-	-	-	78,866	-	(78,866)
SAF	926	-	-	-	-	94,196	-	-	-	(94,196)
SAFCIT2	920	-	-	1,031	-	-	-	-	-	(1,031)
SAFCIT2	921	-	-	-	-	-	-	290	-	(290)
SAFCIT2	923	-	-	-	-	-	-	100	-	(100)
SAFCIT2	926	-	-	-	-	516	-	-	-	(516)
SAFEST	920	-	-	7,342	-	-	-	-	-	(7,342)
SAFEST	921	-	-	-	-	-	-	1,287	-	(1,287)
SAFEST	923	-	-	-	-	-	-	1,500	-	(1,500)
SAFEST	926	-	-	-	-	3,671	-	-	-	(3,671)
SANTA	920	-	-	2,004	-	-	-	-	-	(2,004)
SANTA	921	-	-	-	-	-	-	3,697	-	(3,697)
SANTA	926	-	-	-	-	878	-	-	-	(878)
SCADA	582	-	-	40,694	-	20,347	-	3,157	-	(64,198)
SCADAICCP	582	-	-	-	-	-	-	5,560	-	(5,560)
SCADAMNT	582	-	-	-	-	-	-	34,014	-	(34,014)
SCADAOPS	582	-	-	4,591	-	1,904	-	-	-	(6,495)
SCDAUD17	920	-	-	363	-	-	-	-	-	(363)
SCDAUD17	923	-	-	-	-	-	-	2,925	-	(2,925)
SCDAUD17	926	-	-	-	-	182	-	-	-	(182)
SECAUDIT	920	-	-	175	-	-	-	-	-	(175)
SECAUDIT	923	-	-	-	-	-	-	28,752	-	(28,752)
SECAUDIT	926	-	-	-	-	88	-	-	-	(88)
SECUR	920	-	-	9,833	-	-	-	-	-	(9,833)
SECUR	921	-	-	-	-	-	-	9,711	-	(9,711)
SECUR	926	-	-	-	-	4,917	-	-	-	(4,917)
SECUR	421	-	-	-	-	-	-	-	(15,222)	(15,222)
SECURSYS	920	-	-	949	-	-	-	-	-	(949)
SECURSYS	926	-	-	-	-	475	-	-	-	(475)
SIEM	921	-	-	-	-	-	-	19,582	-	(19,582)
SIPVOIP	920	-	-	77	-	-	-	-	-	(77)

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
SIPVOIP	921	-	-	-	-	-	-	888	-	(888)
SIPVOIP	926	-	-	-	-	38	-	-	-	(38)
SLR	596	-	-	241,868	-	118,044	-	134,285	-	(494,196)
SNOW	920	-	-	12,343	-	-	-	-	-	(12,343)
SNOW	926	-	-	-	-	6,140	-	-	-	(6,140)
SOCMEDIA	909	-	-	1,802	-	901	-	109	-	(2,812)
SOLAR	908	-	-	16,412	-	8,206	-	69,360	-	(93,977)
SOLAR2MW15	908	-	-	1,003	-	502	-	-	-	(1,505)
SOLARFARM4	908	-	-	8,017	-	4,008	-	30,471	-	(42,495)
SOLARRAND3	908	-	-	3,467	-	1,733	-	-	-	(5,200)
SPIRIT	920	-	-	1,017	-	-	-	-	-	(1,017)
SPIRIT	926	-	-	-	-	509	-	-	-	(509)
SPIRIT	930.2	-	-	-	-	-	-	6,847	-	(6,847)
STA	588	-	-	91,823	-	72,314	-	63,292	-	(227,429)
STMTGS	920	-	-	106,177	-	-	-	-	-	(106,177)
STMTGS	921	-	-	-	-	-	-	1,610	-	(1,610)
STMTGS	926	-	-	-	-	52,033	-	-	-	(52,033)
SUBAUD17	923	-	-	-	-	-	-	4,050	-	(4,050)
SUBCOM	582	-	-	13,591	-	6,731	-	6,400	-	(26,721)
SUBLTC	582	-	-	11,583	-	5,792	-	4,232	-	(21,606)
SUBO	582	-	-	173,249	-	80,514	-	41,435	-	(295,197)
SUBRELAY	582	-	-	128,874	-	63,769	-	5,036	-	(197,679)
SUBSWGR	592	-	-	18,928	-	9,112	-	9,668	-	(37,708)
SUBTRAN	592	-	-	54,591	-	26,082	-	27,108	-	(107,781)
SWDIS	581	24,308	15,633	10,422	-	5,211	(15,633)	-	-	8,675
SYS	588	-	-	9,092	-	4,546	-	-	-	(13,638)
TEC	590	-	-	60,517	-	144,251	-	87,983	-	(292,752)
TECHWRITER	581	-	-	16,504	-	8,252	-	-	-	(24,755)
TECR	590	2,621	1,822	1,532	-	290	(1,822)	-	-	799
TIMETRACK	920	-	-	2,574	-	-	-	-	-	(2,574)
TIMETRACK	921	-	-	-	-	-	-	2,857	-	(2,857)
TIMETRACK	923	-	-	-	-	-	-	220	-	(220)
TIMETRACK	926	-	-	-	-	1,287	-	-	-	(1,287)
TOOLREP	588	-	-	9,344	-	4,503	-	18,056	-	(31,903)
TRA	920	-	-	155,228	-	-	-	-	-	(155,228)
TRA	921	-	-	-	-	-	-	77,518	-	(77,518)
TRA	923	-	-	-	-	-	-	101	-	(101)
TRA	926	-	-	-	-	180,405	-	-	-	(180,405)
TRANSFER	903	-	-	150,968	-	74,007	-	3,122	-	(228,097)
TREAS	920	-	-	23,716	-	-	-	-	-	(23,716)
TREAS	921	-	-	-	-	-	-	58,553	-	(58,553)
TREAS	926	-	-	-	-	11,858	-	-	-	(11,858)
TREE	908	-	-	1,672	-	836	-	8,325	-	(10,833)
TREETRUST	908	-	-	-	-	-	-	12,000	-	(12,000)
TRLRS	590	-	-	19,336	-	9,611	-	14,128	-	(43,075)
TRLRS	421	-	-	-	-	-	-	-	(4,502)	(4,502)
TRTRANMOVE	415	6,546	5,756	1,104	-	552	(1,656)	-	-	790
TWPCITY	910	-	-	-	-	-	-	2,096	-	(2,096)
UGSWG	584	-	-	12,889	-	6,437	-	8,486	-	(27,812)
UGTRAN	584	-	-	18,598	-	9,299	-	63,949	-	(91,846)
UNION	920	-	-	3,907	-	-	-	-	-	(3,907)
UNION	921	-	-	-	-	-	(727)	-	-	727
UNION	923	-	-	-	-	-	-	1,600	-	(1,600)
UNION	926	-	-	-	-	1,954	-	-	-	(1,954)
USO	590	-	-	381,251	-	667,295	-	441,958	-	(1,490,504)
USO	421	-	-	-	-	-	-	-	5,113	5,113
USOR	590	317,061	267,040	119,022	-	38,552	(172,980)	15,405	-	50,021
UTIL	590	-	-	19,102	-	9,392	-	(583)	-	(27,912)
UTIL	421	-	-	-	-	-	-	-	2,336	2,336
VANS	920	-	-	17,927	-	-	-	-	-	(17,927)
VANS	921	-	-	-	-	-	(11,490)	(126,194)	-	137,684
VANS	926	-	-	-	-	8,692	-	-	-	(8,692)
VANS	421	-	-	-	-	-	-	-	3,625	3,625

Account or Project	FERC Account	Revenue	Cost of Sales	Internal Labor	*VSH	Payroll Benefits	Reimb.	Other Operating Expenses	Other Inc/ (Loss) Cap Credits, Int., G/L	Income / (Loss)
VISITS	908	-	-	-	-	-	-	8,927	-	(8,927)
VOIP2016	921	-	-	-	-	-	-	1,399	-	(1,399)
VOIP2016	923	-	-	-	-	-	-	690	-	(690)
WARFZ	908	-	-	124	-	62	(3,825)	4,575	-	(936)
WARRF	908	-	-	736	-	364	(15,900)	19,500	-	(4,699)
WCOMP	925	-	-	4,220	-	2,110	-	(6,317)	-	(14)
WEBHOST	909	-	-	-	-	-	-	30,847	-	(30,847)
WEBSITE	909	-	-	7,036	-	3,518	-	16,846	-	(27,400)
WELLNESS	920	-	-	16,317	-	-	-	-	-	(16,317)
WELLNESS	921	-	-	-	-	-	-	26,062	-	(26,062)
WELLNESS	923	-	-	-	-	-	-	22,100	-	(22,100)
WELLNESS	926	-	-	-	-	8,159	-	-	-	(8,159)
WIFI2018	920	-	-	500	-	-	-	-	-	(500)
WIFI2018	921	-	-	-	-	-	-	2,595	-	(2,595)
WIFI2018	926	-	-	-	-	250	-	-	-	(250)
WIRCKS	586	-	-	24,551	-	11,980	-	-	-	(36,531)
WTRHTR	908	-	-	38,896	-	19,443	(14,100)	46,588	-	(90,826)
WTRHTR	415	129,538	128,842	-	-	-	-	-	-	696
WTRHTRNON	415	7,039	5,915	65	-	33	-	825	-	202
WMSMNT	588	-	-	-	-	-	-	51,000	-	(51,000)
YOUTH	910	-	-	4,395	-	1,735	-	15,983	-	(22,113)
		$ 204,031,376	**$ 149,908,591**	**$ 13,873,817**	**$ 2,223,364**	**$ 7,611,463**	**$ (1,531,744)**	**$ 30,290,513**	**$ 5,371,194**	**$ 7,026,566**

*VSH=Vacation, Sick, Holiday and Other Paid Time Off

Workpaper 2
Audited 2018 Financials and
2018 Annual Report

DAKOTA ELECTRIC ASSOCIATION

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2018 AND 2017

DAKOTA ELECTRIC ASSOCIATION
TABLE OF CONTENTS
YEARS ENDED DECEMBER 31, 2018 AND 2017

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CPAs & BUSINESS ADVISORS

Independent Auditor's Report

The Board of Directors
Dakota Electric Association
Farmington, Minnesota

Report on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Dakota Electric Association which comprise the consolidated balance sheets as of December 31, 2018 and 2017, and the related consolidated statements of operations, changes in members' equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dakota Electric Association as of December 31, 2018 and 2017, and the consolidated results of its operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Eide Bailly LLP

Sioux Falls, South Dakota
March 22, 2019

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DAKOTA ELECTRIC ASSOCIATION
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2018 AND 2017
(DOLLARS IN THOUSANDS)

	2018	2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 544	$ 3,081
Accounts Receivable, Less Allowance for Uncollectible Accounts (2018 - $711; 2017 - $676)	29,892	25,541
Conservation Cost and Property Tax Recovery	247	1,009
Inventories, Materials and Supplies	4,184	4,473
Prepayments and Interest Receivable	1,349	1,012
Deferred Charges	-	2
Total Current Assets	36,216	35,118
INVESTMENTS IN ASSOCIATED COMPANIES AND OTHER INVESTMENTS	121,056	117,009
UTILITY PLANT		
Distribution System	267,355	261,606
General Plant	32,987	30,581
Construction Work in Process	4,222	5,114
Less Accumulated Depreciation	(126,122)	(122,693)
Net Utility Plant and Work in Progress	178,442	174,608
DEFERRED CHARGES AND OTHER ASSETS	88	92
Total Assets	$ 335,802	$ 326,827

See accompanying Notes to Consolidated Financial Statements

	2018	2017
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 26,204	$ 29,492
Notes Payable	16,334	12,000
Current Portion of Long-Term Debt	6,900	7,695
Property Tax Over-Recovery	24	-
Customer Security Deposits	505	529
Accrued Property and Other Taxes	4,830	4,925
Other Current Liabilities	8,175	7,785
Total Current Liabilities	62,972	62,426
LONG-TERM DEBT	94,840	90,658
POST-RETIREMENT BENEFIT OBLIGATION	4,609	4,207
DEFERRED CREDITS AND OTHER LIABILITIES	230	337
Total Liabilities	162,651	157,628
MEMBERS' EQUITY	173,151	169,199
Total Liabilities and Members' Equity	$ 335,802	$ 326,827

DAKOTA ELECTRIC ASSOCIATION
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2018 AND 2017
(DOLLARS IN THOUSANDS)

	2018	2017
NET SALES	$ 204,037	$ 202,277
COST OF SALES	149,909	148,448
GROSS MARGIN	54,128	53,829
OPERATING EXPENSES		
Labor and Related Benefits	25,362	23,960
Professional Fees and Services	4,584	3,803
Rebates and Marketing	1,275	1,806
Office Expense	2,402	2,234
Operations and Maintenance	767	907
Depreciation and Amortization	10,336	9,775
Property and Real Estate Taxes	3,372	3,609
Net Interest Expense	4,182	4,068
Other Expenses (Reimbursements)	209	(88)
Total Operating Expenses	52,489	50,074
NET OPERATING MARGIN	1,639	3,755
OTHER INCOME (EXPENSE)		
Interest Income	221	215
Capital Credits from GRE, CFC, CoBank, & Others	5,111	7,166
Other Income (Expense)	39	(72)
Total Other Income	5,371	7,309
NET OPERATING MARGIN AND OTHER INCOME	7,010	11,064
Income Tax Credit on Nonregulated Operations	(17)	(80)
NET INCOME	$ 7,027	$ 11,144

See accompanying Notes to Consolidated Financial Statements

DAKOTA ELECTRIC ASSOCIATION
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' EQUITY
YEARS ENDED DECEMBER 31, 2018 AND 2017
(DOLLARS IN THOUSANDS)

	Patronage Capital and Other Equity
BALANCE, DECEMBER 31, 2016	$ 161,294
Net Income 2017	11,144
Capital Credits Retired - Net	(3,239)
BALANCE, DECEMBER 31, 2017	169,199
Net Income 2018	7,027
Capital Credits Retired - Net	(3,075)
BALANCE, DECEMBER 31, 2018	$ 173,151

See accompanying Notes to Consolidated Financial Statements

DAKOTA ELECTRIC ASSOCIATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2018 AND 2017
(DOLLARS IN THOUSANDS)

	2018	2017
OPERATING ACTIVITIES		
Net Income	$ 7,027	$ 11,144
Adjustments:		
Depreciation and Amortization	10,336	9,775
GRE, CFC, CoBank, and Other Capital Credit Allocations	(5,111)	(7,166)
CFC, CoBank and Other Capital Credits Refunded	555	492
Increase in Current Assets	(3,635)	(3,298)
Decrease in Other Assets	4	4
(Decrease) Increase in Current Liabilities	(2,993)	1,766
Increase in Other Liabilities	295	66
Net Cash from Operating Activities	6,478	12,783
INVESTING ACTIVITIES		
Plant Additions, Net	(13,097)	(14,219)
Funds Received from Maturity of CFC Investment Certificates	509	58
Net Cash Used for Investing Activities	(12,588)	(14,161)
FINANCING ACTIVITIES		
Loan Advances Received	10,000	10,000
Principal Payments on Long-Term Debt	(7,686)	(7,250)
Increase in Notes Payable	4,334	1,100
Patronage Capital Retirements Paid	(3,075)	(3,239)
Net Cash from Financing Activities	3,573	611
Net Change in Cash and Cash Equivalents	(2,537)	(767)
Cash and Cash Equivalents, Beginning of Year	3,081	3,848
Cash and Cash Equivalents, End of Year	$ 544	$ 3,081
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash Paid for		
Interest	$ 4,297	$ 4,142
Income Taxes	1	2
SUPPLEMENTAL DISCLOSURE OF NON-CASH FINANCING ACTIVITIES		
Equipment Acquired Through Capital Leases	$ 1,073	$ 777

See accompanying Notes to Consolidated Financial Statements

DAKOTA ELECTRIC ASSOCIATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2018 AND 2017

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Dakota Electric Association (Dakota Electric) is a 108,000 member not-for-profit, member-owned electric distribution cooperative serving homes and businesses primarily in Dakota County, Minnesota. Dakota Electric also has a for-profit wholly-owned subsidiary, Midwest Energy Services (MES), which wholly-owns Energy Alternatives Parent (EA). EA wholly-owns Energy Alternatives Solar L.L.C. (EAS). EAS leased non-member customer-sited solar photovoltaic generation and divested or exited the leases in 2018.

As a rate-regulated cooperative, Dakota Electric applies Accounting Standards Codification (ASC) 980 Regulated Operations. The application of generally accepted accounting principles by Dakota Electric differs in certain respects from the application by nonregulated businesses as a result of applying ASC 980. Such differences generally relate to the time at which certain items enter into the determination of net margins in order to follow the principle of matching costs and revenues.

Consolidation Policy and Preparation of Financial Statements

The accompanying consolidated financial statements include the accounts of Dakota Electric and its wholly-owned subsidiary. All significant intercompany transactions and balances have been eliminated.

Regulation

Dakota Electric is subject to regulation by the Minnesota Public Utilities Commission (MPUC). Dakota Electric's accounting policies and the accompanying consolidated financial statements conform to generally accepted accounting principles applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

Revenue Recognition

Rates charged to members are established by the board of directors and are subject to approval by the MPUC before becoming effective. Billings are rendered on a cycle basis and revenue is accrued for service provided but not yet billed. Electric rates include adjustment clauses, which bill or credit members for purchased power, conservation, and property tax costs above or below the base levels in rate schedules.

Receivables and Credit Policies

Trade receivables are uncollateralized member obligations due under normal trade terms requiring payment within 25 days from the billing date. Unpaid trade receivables with dates over 30 days old are assessed a $1 late fee or interest at 1.5% of the unpaid balance, whichever is greater. Payments on trade and notes receivable are allocated to the earliest unpaid billings. The carrying amounts of trade and notes receivable are reduced by a valuation allowance that reflects management's best estimate of the amount that will not be collected. Management reviews all trade and notes receivable balances periodically and adjusts the allowance accounts based on current economic conditions and past experience.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Property and Depreciation

Plant is recorded at original cost. The cost of additions to utility plant and replacement of retirement units of property are capitalized. Maintenance costs and replacements of minor items of property are charged to expense as incurred. Costs of depreciable units of utility plant retired are eliminated from the plant accounts. Such costs plus removal expenses less salvage are charged to accumulated depreciation.

Depreciation of Dakota Electric utility plant is computed using rates approved by the MPUC based on estimated useful lives of the various classes of property. In 2018 and 2017, provisions for depreciation approximated 3.5% and 3.4%, respectively, of the average original cost of depreciable property.

Cash and Cash Equivalents

Dakota Electric considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. Cash equivalents are stated at cost, which approximates market value.

Materials and Supplies

Materials and supplies are stated at average cost.

Investments in Associated Companies

Investments principally represent undistributed allocated margins of other cooperatives and investment certificates in the Cooperative Finance Corporation (CFC). These investments are recorded at cost.

Patronage Capital

Dakota Electric operates on a nonprofit basis. Amounts received from the furnishing of electric energy in excess of operating costs and expenses are assigned to members on a patronage basis. Other amounts received by Dakota Electric from its operations in excess of costs and expenses are either allocated to members on a patronage basis or included in other equities in accordance with the bylaws.

Sales Taxes

Dakota Electric has members in municipalities in which those governmental units impose a sales tax on certain sales. Dakota Electric collects those sales taxes from its members and remits the entire amount to the various governmental units. Dakota Electric's accounting policy is to exclude the tax collected and remitted from revenue and cost of sales.

Income Taxes

Dakota Electric is exempt from income taxes under Section 501 (c) (12) of the Internal Revenue Code and the State of Minnesota. MES provides for deferred taxes on temporary differences arising from assets and liabilities whose basis is different for financial reporting and income tax purposes.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Income Taxes (Continued)

Dakota Electric will recognize future accrued interest and penalties related to unrecognized tax benefits in income tax expense if such penalties and interest are incurred. Under normal circumstances, Dakota Electric, MES and its subsidiaries are no longer subject to federal or state tax examinations by tax authorities for years before 2016.

Dakota Electric and subsidiaries undergo an annual analysis of various tax positions, assessing the likelihood of those positions being upheld upon examination with relevant tax authorities, as defined by ASC 740-10. The unrecognized tax benefit accrual was zero as of December 31, 2018 and December 31, 2017.

Deferred Gain on RUS Buyout

In 1994 and 1995, Dakota Electric refinanced long-term debt payable to the Rural Utilities Service (RUS) with CFC. The early extinguishments resulted in gains of $11.3 million, which are being amortized over the lives of the related CFC debt (24 and 32 years, respectively) using the sum of the year's digits method. Interest expense is net of amortization of $76,000 and $110,000 in 2018 and 2017, respectively.

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Concentrations of Credit Risk

Financial instruments, which potentially subject Dakota Electric to concentrations of credit risk, consist primarily of temporary cash investments and trade receivables. Dakota Electric invests excess cash with various high-quality financial institutions and, by policy, generally limits the amount of credit exposure to any one financial institution. Concentrations of credit risk with respect to trade receivables are limited due to Dakota Electric's large number of members and their dispersion across many industries. Dakota Electric does not obtain collateral to support trade receivables. Dakota Electric has not incurred and does not expect to incur significant credit losses.

Dakota Electric maintains its cash accounts in area financial institutions. The balances are insured by the Federal Deposit Insurance Corporation up to $250,000. At various times during the year, Dakota Electric's cash balances exceed insurance.

Concentration of Sources of Labor

At December 31, 2018, Dakota Electric had collective bargaining agreements covering 107 employees which represented 57% of total full-time employees. The collective bargaining agreements expire on December 31, 2020.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Reclassifications

Certain reclassifications of amounts previously reported have been made to the accompanying consolidated financial statements to maintain consistency between periods presented. The reclassifications had no impact on net margin or members' equity.

Subsequent Events

Dakota Electric has evaluated subsequent events through March 22, 2019 the date which the financial statements were available to be issued.

NOTE 2 SUBSIDIARY OPERATING RESULTS

MES operating results for the years ended December 31, 2018 and 2017 are summarized below.

	2018	2017
	(in thousands)	
Revenues	$ 12	$ 63
Operating Expenses, Other Income and Expense	21	302
Loss Before Taxes	(9)	(239)
Income Tax Credit	(17)	(80)
Net Income (Loss)	$ 8	$ (159)

At December 31, 2017, MES deferred tax liability totaled $30,000. MES significant temporary differences resulted from differences in depreciation for financial reporting and income tax reporting. At December 31, 2018, MES had no depreciable assets and therefore, no deferred tax liability. Net current deferred tax assets relate to the difference in timing of deferred lease revenue and state net operating loss carryforwards. An offsetting valuation allowance is recorded as the certainty of realizing the future tax benefits of the state operating loss carryforward is uncertain at this time. The deferred tax asset balance was $2,000 at December 31, 2017. At December 31, 2018, MES had no deferred lease revenue and therefore, no deferred tax asset.

NOTE 3 INVESTMENTS IN ASSOCIATED COMPANIES AND OTHER INVESTMENTS

	2018	2017
	(in thousands)	
Great River Energy		
Patronage Capital	$ 110,753	$ 106,442
Cooperative Finance Corporation		
Capital Term Certificates -		
Maturities 2070 - 2080, Interest Rate 5.0%	1,419	1,419
Loan Term Certificates -		
Maturities 2020 - 2030, Interest Rate 3.0%	532	532
Loan Term Certificates -		
Maturities 2019 - 2044, Interest Rate 0.0%	1,017	1,564
Member Capital Securities -		
Maturity 2044, Interest Rate 5.0%	1,000	1,000
Patronage Capital	4,260	4,155
	8,228	8,670
Other Investments	2,075	1,897
Total Investments in Associated Companies and Other Investments	$ 121,056	$ 117,009

Investment in Great River Energy (GRE) represents undistributed allocated margins. Dakota Electric's share of annual GRE margins is generally based on the percentage of GRE's total power generation purchased by Dakota Electric. Under its wholesale power purchase agreement, Dakota Electric is committed to purchase at least 95% of its electric power requirements from GRE until December 31, 2045. The rates paid are subject to change annually.

Investments in CFC represent undistributed patronage capital allocated to Dakota Electric as well as loan and capital term certificates, and member capital securities. The certificates represent investments made pursuant to CFC borrowing requirements.

NOTE 4 PATRONAGE CAPITAL AND OTHER EQUITY

Dakota Electric has covenants with its lenders that restrict the retirement of patronage capital. After retirement, the capital of Dakota Electric must equal at least 30% of its total assets. No distributions can be made if there is unpaid, when due, any installments of principal or interest on the notes.

Capital credit retirements for estates, members reaching age 65, and members moving off-line after July 1, 1998 are made upon request. Patronage capital credits arising from prior years' margins are retired as determined annually by the board of directors. As of December 31, 2018, capital credits through 1990 and 65% of 1991 have substantially been retired.

NOTE 5 LONG-TERM DEBT

	2018	2017
	(in thousands)	
Cooperative Finance Corporation (CFC) mortgage notes 2.50% to 4.50%, due in quarterly installments through 2048.	$ 67,415	$ 61,776
CoBank mortgage notes 1.91% to 4.56%, due in monthly installments through 2043.	32,433	35,292
Capital Lease Provision (Note 6)	1,892	1,285
	101,740	98,353
Less Current Portion	(6,900)	(7,695)
Long-Term Debt	$ 94,840	$ 90,658

Substantially all assets are pledged as security on the mortgage notes. There are certain notes that contain provisions for changing interest rates at specified future dates.

Dakota Electric's debt agreements contain various restrictive covenants. Management believes Dakota Electric was in compliance with all restrictive covenants as of December 31, 2018 and 2017.

It is estimated that principal repayments on the above debt for the next five years, and thereafter, will be as follows:

Years Ending December 31,	Total
	(in thousands)
2019	$ 6,900
2020	6,677
2021	6,299
2022	6,550
2023	6,242
Thereafter	69,072
	$ 101,740

NOTE 6 CAPITAL LEASE PROVISION

Dakota Electric leases computer equipment and heavy vehicles under various long-term lease agreements. The leases expire at various dates through 2023.

Future minimum lease payments are as follows:

Years Ending December 31,		Capital Leases
		(in thousands)
2019	$	595
2020		422
2021		295
2022		426
2023		382
Total minimum lease payments		2,120
Less portion representing interest		(228)
Present value of minimum lease payments - Note 5	$	1,892

Leased property under capital leases at December 31, 2018 and 2017 includes:

		2018		2017
		(in thousands)		
Computer Equipment	$	406	$	349
Heavy Equipment		2,133		3,279
Total		2,539		3,628
Less accumulated amortization		(701)		(1,019)
Net Book Value	$	1,838	$	2,609

NOTE 7 NOTES PAYABLE (LINES OF CREDIT)

Dakota Electric has executed an as-offered uncommitted perpetual line of credit agreement providing Dakota Electric with short term loans of up to $30 million on a revolving basis with CFC. Interest on unpaid principal is payable quarterly at rates established by CFC; this rate was 3.35% at December 31, 2018. There were outstanding balances of $16,334,000 and $1,100,000 on this line of credit at December 31, 2018 and 2017, respectively.

NOTE 7 NOTES PAYABLE (LINES OF CREDIT) (CONTINUED)

Dakota Electric has a $30 million line of credit agreement with CoBank, which expires September 30, 2019 and will subsequently be renewed. This agreement imposes a maximum of $30 million outstanding unsecured debt at any one time to all lenders. Interest on unpaid principal is payable monthly at rates established by CoBank on a weekly basis (4.46% at December 31, 2018). There were outstanding balances of $0 and $10,900,000 on this line of credit at December 31, 2018 and 2017, respectively.

NOTE 8 OTHER CURRENT LIABILITIES

	2018	2017
	(in thousands)	
Accrued Interest	$ 584	$ 626
Accrued Payroll	611	463
Accrued Sick Leave	1,261	1,284
Accrued Vacation	1,468	1,473
Unclaimed Capital Credits	4,053	3,835
Other	198	104
	$ 8,175	$ 7,785

NOTE 9 PENSION PLANS

The majority of employees of Dakota Electric participate in the National Rural Electric Cooperative Association (NRECA) Retirement & Security Plan (RS Plan), a defined benefit pension plan qualified under section 401 and tax exempt under section 501(a) of the Internal Revenue Code. It is considered a multiemployer plan under the accounting standards. The plan sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333.

A unique characteristic of a multi-employer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

NOTE 9 PENSION PLANS (CONTINUED)

Dakota Electric makes contributions to the RS Plan equal to the amounts accrued for pension expense except for the periods when a moratorium on contributions has been in effect due to the plan reaching full funding limitations. Dakota Electric's contributions to the RS Plan in 2018 and in 2017 represented less than 5 percent of the total contributions made to the plan by all participating employers. Contributions to the plan for the years ended December 31, 2018 and 2017, were approximately $3,092,000 and $3,085,000, respectively. There have been no significant changes that affect the comparability of 2018 and 2017 contributions.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act (PPA) of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80% funded on January 1, 2018 and over 80% funded on January 1, 2017, based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

Dakota Electric has defined contribution savings plans for employees who meet certain age and service requirements. Dakota Electric contributed between 4.0% and 10.0% in 2018 and 2017 of eligible employees' compensation. Savings plan company contributions for the years ended December 31, 2018 and 2017, were approximately $1,061,000 and $992,000, respectively.

NOTE 10 POST-RETIREMENT BENEFITS OTHER THAN PENSIONS

Dakota Electric provides certain health care benefits for salaried and hourly retired employees. Employees may become eligible for these health care benefits after attaining specified age and service requirements prior to retiring from Dakota Electric.

Dakota Electric is required to disclose the following information according to Accounting Standards Codification (ASC) 715 Compensation-Retirement Benefits in the notes to the financial statements.

NOTE 10 POST-RETIREMENT BENEFITS OTHER THAN PENSIONS (CONTINUED)

The following table sets forth the plan's funded status reconciled with the obligation recognized in the accompanying balance sheet at December 31:

	2018	2017
	(in thousands)	
Change in Post-retirement Benefit Obligation		
Accumulated Post-retirement		
Benefit Obligation at Beginning of Year	$ 4,207	$ 3,925
Interest and Service Cost	540	414
Benefits Paid-Net of Retiree Contributions	(138)	(132)
Accumulated Post-retirement Benefit Obligation at End of Year	4,609	4,207
Change in Plan Assets		
Plan Assets at Beginning of Year	-	-
Employer Contributions	138	132
Benefits Paid-Net of Retiree Contributions	(138)	(132)
Plan Assets at End of Year	-	-
Funded Status	(4,609)	(4,207)
Net Post-retirement Benefit Obligation Recognized	$ (4,609)	$ (4,207)
Weighted Average Assumptions at December 31:		
Discount Rate	4.87%	4.87%

For measurement purposes, a 4.88% and 4.96% annual rate of increase in per capita cost of health care benefits was assumed for 2018 and 2017, respectively. Accelerating the rate of assumed health care costs by 1% each year would increase the benefit obligation as of December 31, 2018 and 2017 by $385,000 and $360,000, respectively.

Post-retirement benefit payments over the next 10 years are estimated to be as follows:

Years ending December 31,	Estimated Payments (in thousands)
2019	$ 138
2020	144
2021	151
2022	159
2023	167
2024 - 2028	963

NOTE 11 RELATED PARTY TRANSACTIONS

Dakota Electric is a member of and purchases its wholesale power from Great River Energy. The following is a summary of material transactions with Great River Energy for the years ended December 31, 2018 and 2017:

	2018	2017
	(in thousands)	
Purchase of Wholesale Power	$ 149,330	$ 147,875
Account Receivable	$ 13	$ -
Accounts Payable for Purchased Power	$ 19,325	$ 21,957
Capital Credit Allocation	$ 4,311	$ 6,404
Accumulated Investment in Patronage Capital	$ 110,753	$ 106,442

NOTE 12 FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of financial instruments have been derived, in part, by management's assumptions, the estimated amount and timing of future cash flows and estimated discount rates. Different assumptions could significantly affect these estimated fair values. Accordingly, the net realizable value could be materially different from the estimates. In addition, the estimates are only indicative of the value of individual financial instruments and should not be considered an indication of the fair value of the Association. The following disclosures represent financial instruments in which the ending balances at December 31, 2018 and 2017 are not carried at fair value in their entirety on the Consolidated Balance Sheets.

The following methods and assumptions were used to estimate the fair value of a class of financial instruments at December 31, 2018 and 2017 for which it is practicable to estimate that value:

Cash and Cash Equivalents

The carrying amount approximates fair value because of the short-term maturity of these instruments.

Investment in Associated Companies

The investments are not actively traded and fair value is not readily estimable.

Notes Payable and Long-Term Debt

The carrying amount approximates fair value based on current rates available to Dakota Electric for debt of similar maturities.

Consolidated Balance Sheets

ASSETS

	2018	2017
	(in thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$544	$3,081
Accounts receivable, less allowance for uncollectible accounts (2018 - $711; 2017 - $676)	29,892	25,541
Conservation cost and property tax recovery	247	1,009
Inventories, materials and supplies	4,184	4,473
Prepayments and interest receivable	1,349	1,012
Deferred charges	-	2
Total current assets	36,216	35,118
Investments in associated companies and other investments	121,056	117,009
UTILITY PLANT		
Distribution system	267,355	261,606
General plant	32,987	30,581
Construction work in progress	4,222	5,114
Less accumulated depreciation	(126,122)	(122,693)
Net utility plant and work in progress	178,442	174,608
Deferred charges and other assets	88	92
TOTAL ASSETS	**$335,802**	**$326,827**

LIABILITIES AND EQUITY

	2018	2017
CURRENT LIABILITIES		
Accounts payable	$26,204	$29,492
Notes payable	16,334	12,000
Current portion of long-term debt	6,900	7,695
Property tax over-recovery	24	0
Customer security deposits	505	529
Accrued property and other taxes	4,830	4,925
Other current liabilities	8,175	7,785
Total current liabilities	62,972	62,426
Long-term debt	94,840	90,658
Post-retirement benefit obligation	4,609	4,207
Deferred credits and other liabilities	230	337
Total liabilities	162,651	157,628
MEMBERS' EQUITY		
Patronage capital and other equity	173,151	169,199
TOTAL LIABILITIES AND MEMBERS' EQUITY	**$335,802**	**$326,827**

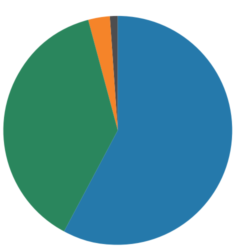
Consolidated Statements of Operations

	2018	2017
	(in thousands)	
OPERATING REVENUES		
Net sales	$204,037	$202,277
Cost of power / Cost of sales	149,909	148,448
Gross margin	54,128	53,829
OPERATING EXPENSES		
Total operating expenses	52,489	50,074
Net operating margin	1,639	3,755
OTHER INCOME		
Total other income	5,371	7,309
Income before taxes	7,010	11,064
Income tax (credit) on non-regulated operations	(17)	(80)
NET INCOME	**$7,027**	**$11,144**

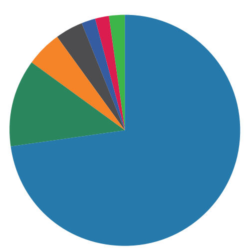
Consolidated Statements of Cash Flows

Net cash provided by operations	$5,923	$12,291
Net cash used for investing activities	(13,106)	(14,446)
Net cash from financing activities	4,646	1,388
Net change in cash and cash equivalents	(2,537)	(767)
Cash and cash equivalents at beginning of year	3,081	3,848
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$544**	**$3,081**

Financial information presented in this report is summarized. Members may request a copy of the complete audited financial statements or view them online at dakotaelectric.com.



2018 Sources of Electric Revenue



2018 Uses of Revenue

Workpaper 1
Form 7s 2014 - 2018

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric Association
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2014

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION	BALANCE CHECK RESULTS	AUTHORIZATION CHOICES
We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.	0 Needs Attention	A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA? YES (selected) / NO
[redacted] 3/18/2015 Signature of Office Manager or Accountant — Date	1 Please Review	
[redacted] 3/18/15 Signature of Manager — Date	20 Matches	B. Will you authorize CFC to share your data with other cooperatives? YES (selected) / NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	193,896,154	195,879,147	0	0
2. Power Production Expense	0		0	0
3. Cost of Purchased Power	144,652,939	146,449,389	0	0
4. Transmission Expense	0		0	0
5. Regional Market Operations Expense	0		0	0
6. Distribution Expense - Operation	6,795,123	6,788,118	0	0
7. Distribution Expense - Maintenance	5,884,708	5,811,128	0	0
8. Consumer Accounts Expense	4,214,264	4,252,599	0	0
9. Customer Service and Informational Expense	3,288,198	3,053,562	0	0
10. Sales Expense	0	0	0	0
11. Administrative and General Expense	9,361,904	9,997,478	0	0
12. Total Operation & Maintenance Expense (2 thru 11)	**174,197,136**	**176,352,274**	**0**	**0**
13. Depreciation & Amortization Expense	8,419,183	8,574,817	0	0
14. Tax Expense - Property & Gross Receipts	3,521,344	3,325,897	0	0
15. Tax Expense - Other	See Note(1)on Page 2	See Note(1)on Page 2	0	0
16. Interest on Long-Term Debt	5,322,466	5,112,567	0	0
17. Interest Charged to Construction (Credit)	0		0	0
18. Interest Expense - Other	283,445	293,365	0	0
19. Other Deductions	(168,628)	(80,874)	0	0
20. Total Cost of Electric Service (12 thru 19)	**191,574,946**	**193,578,046**	**0**	**0**
21. Patronage Capital & Operating Margins (1 minus 20)	**2,321,208**	**2,301,101**	**0**	**0**
22. Non Operating Margins - Interest	155,968	160,823	0	0
23. Allowance for Funds Used During Construction	0		0	0
24. Income (Loss) from Equity Investments	272,889	(123,548)	0	0
25. Non Operating Margins - Other	(29,710)	54,213	0	0
26. Generation & Transmission Capital Credits	7,931,003	9,989,099	0	0
27. Other Capital Credits & Patronage Dividends	763,769	753,619	0	0
28. Extraordinary Items	0		0	0
29. Patronage Capital or Margins (21 thru 28)	**11,415,127**	**13,135,307**	**0**	**0**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	712	722	5. Miles Transmission	0	0
2. Services Retired	90	94	6. Miles Distribution Overhead	1,220	1,215
3. Total Services In Place	103,438	104,066	7. Miles Distribution Underground	2,792	2,819
4. Idle Services (Exclude Seasonal)	403	433	**8. Total Miles Energized (5+6+7)**	**4,012**	**4,034**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT			
		BORROWER NAME	Dakota Electric
		BORROWER DESIGNATION	MN065
		ENDING DATE	12/31/2014

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	264,572,661	29. Memberships	0
2. Construction Work in Progress	5,410,451	30. Patronage Capital	48,722,199
3. Total Utility Plant (1+2)	**269,983,112**	31. Operating Margins - Prior Years	0
4. Accum. Provision for Depreciation and Amort	108,120,237	32. Operating Margins - Current Year	2,301,101
5. Net Utility Plant (3-4)	**161,862,875**	33. Non-Operating Margins	10,834,206
6. Nonutility Property - Net	0	34. Other Margins & Equities	85,551,609
7. Investment in Subsidiary Companies	4,994,300	**35. Total Margins & Equities (29 thru 34)**	**147,409,115**
8. Invest. in Assoc. Org. - Patronage Capital	95,388,550	36. Long-Term Debt CFC (Net)	67,652,012
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	23,405,349
10. Invest in Assoc. Org. - Other - Nongeneral Funds	5,013,078	**38. Total Long-Term Debt (36 + 37)**	**91,057,361**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	630,856
12. Other Investments	0	40. Accumulated Operating Provisions - Asset Retirement Obligations	3,915,000
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**4,545,856**
14. Total Other Property & Investments (6 thru 13)	**105,395,928**	42. Notes Payable	13,000,000
15. Cash-General Funds	447,791	43. Accounts Payable	24,776,747
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	573,053
17. Special Deposits	0	45. Current Maturities Long-Term Debt	5,547,690
18. Temporary Investments	0	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	356,285
20. Accounts Receivable - Net Sales of Energy	18,608,267	48. Other Current & Accrued Liabilities	10,880,018
21. Accounts Receivable - Net Other	608,039	**49. Total Current & Accrued Liabilities (42 thru 48)**	**55,133,793**
22. Renewable Energy Credits	0	50. Deferred Credits	811,972
23. Materials & Supplies - Electric and Other	5,257,918	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**298,958,097**
24. Prepayments	1,022,501		
25. Other Current & Accrued Assets	3,820,806	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**29,765,322**	Balance Beginning of Year	46,413,661
27. Deferred Debits	1,933,972	Amounts Received This Year (Net)	1,541,962
28. Total Assets & Other Debits (5+14+26+27)	**298,958,097**	**TOTAL Contributions-In-Aid-Of-Construction**	**47,955,623**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

Note (1): Part A, line 15. The payroll taxes (FICA, FUTA & SUTA) were fully allocated to the expenses included in Part A, lines 6,7,8,9 and 11. The expense for line 15 that was allocated totaled $1,072,426 for 2014 and $1,087,181 for 2013.

Note (2): Part A, line 16 includes $52,205 of interest on capital lease obligations.

Note (3): Part C. line 25 includes $3,789,356 of unbilled revenue not billed to consumers for which kWhs have been consumed.

Note (4): Part C. line 32 is the operating income from page 1, Part A. Line 20 (b) only. Capital credits from page 1, Part A. lines 26(b) and 27(b) are included in Part C. line 33.

Note (5):Part R. line 4 includes only accounts with less than 15KW of demand. In 2004, DEA implemented a new rate structure that combined the accounts with 15KW or greater demand with the large commercial included on line 5.

Note (6):Part K. line 2 in 2014 is the amount written off during the year not including recoveries. The amount net of recoveries is $433,829.

Note (7):Part S. Per Bettina Kimmel at CFC, this information is not required. DEA provides it annually to our power supplier, Great River Energy, who consolidates the information for all their members and reports it to the MN Public Utilities Commission. DEA does not calculate or report the information to GRE on an MBTU basis.

Please refer to Dakota Electric's 2014 Audited Financial Statements for additional information.

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	
BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2014

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	233,534,423	8,830,417	3,922,185	0	**238,442,655**
2	General Plant Subtotal	17,772,792	1,150,408	756,772	0	**18,166,428**
3	Headquarters Plant	7,861,521	209,431	107,374	0	**7,963,578**
4	Intangibles	0	0	0	0	**0**
5	Transmission Plant Subtotal	0	0	0	0	**0**
6	Regional Transmission and Market Operation Plant	0	0	0	0	**0**
7	Production Plant - Steam	0	0	0	0	**0**
8	Production Plant - Nuclear	0	0	0	0	**0**
9	Production Plant - Hydro	0	0	0	0	**0**
10	Production Plant - Other	0	0	0	0	**0**
11	All Other Utility Plant	0	0	0	0	**0**
12	**SUBTOTAL: (1 thru 11)**	**259,168,736**	**10,190,256**	**4,786,331**	**0**	**264,572,661**
13	Construction Work in Progress	5,053,958	356,493			**5,410,451**
14	**TOTAL UTILITY PLANT (12+13)**	**264,222,694**	**10,546,749**	**4,786,331**	**0**	**269,983,112**

CFC NO LONGER REQUIRES SECTIONS "F", "G", AND "N" DATA
Those sections refer to data on "Analysis of Accumulated Provision for Depreciation" (F),
"Materials and Supplies" (G), "Annual Meeting and Board Data" (N), and "Conservation Data" (P).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	TOTAL (e)
		Power Supplier (a)	Major Event (b)	Planned (c)	All Other (d)	
1.	Present Year	1.27	2.30	1.42	25.55	**30.54**
2.	Five-Year Average	7.13	17.68	1.30	23.55	**49.66**

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	195	4. Payroll - Expensed	12,070,171
2.	Employee - Hours Worked - Regular Time	414,835	5. Payroll - Capitalized	2,077,570
3.	Employee - Hours Worked - Overtime	7,650	6. Payroll - Other	2,091,401

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1.	General Retirement	1,991,203	21,441,461
2.	Special Retirements	863,318	12,483,626
3.	**Total Retirements (1+2)**	**2,854,521**	**33,925,087**
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5.	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric System	347,308	
6.	**Total Cash Received (4+5)**	**347,308**	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1. Amount Due Over 60 Days:	1,745,557
2. Amount Written Off During Year:	584,856

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

PART L. KWH PURCHASED AND TOTAL COST

	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST: WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Great River Energy			0 None	1,878,103,341	145,694,142	7.76	0	0	Comments
2	Great River Energy			1 Wind	9,258,300	755,247	8.16	0	0	Comments
3				0 None	0	0	0.00	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5				0 None	0	0	0.00	0	0	Comments
6				0 None	0	0	0.00	0	0	Comments
7				0 None	0	0	0.00	0	0	Comments
8				0 None	0	0	0.00	0	0	Comments
9				0 None	0	0	0.00	0	0	Comments
10				0 None	0	0	0.00	0	0	Comments
11				0 None	0	0	0.00	0	0	Comments
12				0 None	0	0	0.00	0	0	Comments
13				0 None	0	0	0.00	0	0	Comments
14				0 None	0	0	0.00	0	0	Comments
15				0 None	0	0	0.00	0	0	Comments
16				0 None	0	0	0.00	0	0	Comments
17				0 None	0	0	0.00	0	0	Comments
18				0 None	0	0	0.00	0	0	Comments
19				0 None	0	0	0.00	0	0	Comments
20				0 None	0	0	0.00	0	0	Comments
21	**TOTALS**				**1,887,361,641**	**146,449,389**	**7.76**	**0**	**0**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1	
2	
3	
4	
5	
6	
7	
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9	
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12	
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CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.			$0
2.			$0
3.		TOTAL	**$0**

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	PRINCIPAL (b)	TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	63,926,880	4,198,588	4,049,728	8,248,316	
2	NCSC		0	0	0	
3	Farmer Mac	7,305,799	307,460	422,334	729,794	
4	CoBank	25,372,372	620,910	1,247,821	1,868,731	
5		0	0	0	0	
6		0	0	0	0	
7		0	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10	Principal Payments Received from Ultimate Recipients of IRP Loans			0		
11	Principal Payments Received from Ultimate Recipients of REDL Loans			0		
12	**TOTAL (Sum of 1 thru 9)**	**$96,605,051**	**$5,126,958**	**$5,719,883**	**$10,846,841**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

PART R. POWER REQUIREMENTS DATA BASE

CLASSIFICATION	CONSUMER, SALES, AND REVENUE DATA	JANUARY CONSUMERS (a)	DECEMBER CONSUMERS (b)	AVERAGE CONSUMERS (c)	TOTAL KWH SALES AND REVENUE (d)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	95,345	95,815	95,580	
	b. KWH Sold				906,694,356
	c. Revenue				112,078,753
2. Residential Sales - Seasonal	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
3. Irrigation Sales	a. No. Consumers Served	369	380	375	
	b. KWH Sold				8,586,903
	c. Revenue				909,554
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	4,479	4,371	4,425	
	b. KWH Sold				49,137,492
	c. Revenue				6,051,503
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	2,634	2,780	2,707	
	b. KWH Sold				853,612,279
	c. Revenue				73,426,208
6. Public Street & Highway Lighting	a. No. Consumers Served	223	222	223	
	b. KWH Sold				10,404,289
	c. Revenue				1,988,891
7. Other Sales to Public Authority	a. No. Consumers Served	65	65	65	
	b. KWH Sold				0
	c. Revenue				3,900
8. Sales for Resales-RUS Borrowers	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		**103,115**	**103,633**	**103,374**	0
11. TOTAL KWH Sold (lines 1b thru 9b)					**1,828,435,319**
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					**194,458,809**
13. Transmission Revenue					0
14. Other Electric Revenue					1,420,338
15. KWH - Own Use					2,305,477
16. TOTAL KWH Purchased					1,887,361,641
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					146,449,389
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)	○ Non-coincident ◉ Coincident				3,617,186

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	0	0	0	0	0
2.	Residential Sales - Seasonal	0	0	0	0	0	0
3.	Irrigation Sales	0	0	0	0	0	0
4.	Comm. and Ind. 1000 KVA or Less	0	0	0	0	0	0
5.	Comm. and Ind. Over 1000 KVA	0	0	0	0	0	0
6.	Public Street and Highway Lighting	0	0	0	0	0	0
7.	Other Sales to Public Authorities	0	0	0	0	0	0
8.	Sales for Resales - RUS Borrowers	0	0	0	0	0	0
9.	Sales for Resales - Other	0	0	0	0	0	0
10.	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2014

(All investments refer to your most recent CFC Loan Agreement)

7a - PART 1 - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2. INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
5	Capital Term Certificates and Member Capital Securities	0	4,900,548	
6	Patronage Capital GRE	0	90,360,875	
7	Patronage Capital NRUCFC	0	3,772,793	
8	Other	6,361,712		
	Subtotal (Line 5 thru 8)	**6,361,712**	**99,034,216**	**0**
3. INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
9				
10				
11				
12				
	Subtotal (Line 9 thru 12)	**0**	**0**	**0**
4. OTHER INVESTMENTS				
13				
14				
15				
16				
	Subtotal (Line 13 thru 16)	**0**	**0**	**0**
5. SPECIAL FUNDS				
17				
18				
19				
20				
	Subtotal (Line 17 thru 20)	**0**	**0**	**0**
6. CASH - GENERAL				
21	Anchor Bank-Farmington	93,483	250,000	
22	Wells Fargo		103,800	
23	Petty Cash	508		
24				
	Subtotal (Line 21 thru 24)	**93,991**	**353,800**	**0**
7. SPECIAL DEPOSITS				
25				
26				
27				
28				
	Subtotal (Line 25 thru 28)	**0**	**0**	**0**
8. TEMPORARY INVESTMENTS				
29				
30				
31				
32				
	Subtotal (Line 29 thru 32)	**0**	**0**	**0**
9. ACCOUNT & NOTES RECEIVABLE - NET				
33	Accounts Receivable - Non Electric Billing	552,829		
34	Accounts Receivable - Other	55,210		
35				
36				
	Subtotal (Line 33 thru 36)	**608,039**	**0**	**0**
10. COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED				
37				
38				
39				
40				
	Subtotal (Line 37 thru 40)	**0**	**0**	**0**
	Total	**7,063,742**	**99,388,016**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2014

(All investments refer to your most recent CFC Loan Agreement)

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		**7,063,742**
2	LARGER OF (a) OR (b)		**73,704,558**
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	**40,497,467**	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	**73,704,558**	

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric Association
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION	BALANCE CHECK RESULTS	AUTHORIZATION CHOICES
We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.	0 Needs Attention	A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA? YES NO
[redacted] 3/28/16 Signature of Office Manager or Accountant — Date	0 Please Review	
[redacted] 3/28/16 Signature of Manager — Date	21 Matches	B. Will you authorize CFC to share your data with other cooperatives? YES NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	195,879,147	192,551,946	0	0
2. Power Production Expense		0	0	0
3. Cost of Purchased Power	146,449,389	141,565,239	0	0
4. Transmission Expense		0	0	0
5. Regional Market Operations Expense		0	0	0
6. Distribution Expense - Operation	6,788,118	6,871,777	0	0
7. Distribution Expense - Maintenance	5,811,128	5,653,587	0	0
8. Consumer Accounts Expense	4,252,599	4,743,770	0	0
9. Customer Service and Informational Expense	3,053,562	3,347,544	0	0
10. Sales Expense	0		0	0
11. Administrative and General Expense	9,997,478	10,428,717	0	0
12. Total Operation & Maintenance Expense (2 thru 11)	**176,352,274**	**172,610,634**	**0**	**0**
13. Depreciation & Amortization Expense	8,574,817	8,716,070	0	0
14. Tax Expense - Property & Gross Receipts	3,325,897	3,443,074	0	0
15. Tax Expense - Other	0	0	0	0
16. Interest on Long-Term Debt	5,112,567	4,524,806	0	0
17. Interest Charged to Construction (Credit)			0	0
18. Interest Expense - Other	293,365	279,391	0	0
19. Other Deductions	(80,874)	(80,262)	0	0
20. Total Cost of Electric Service (12 thru 19)	**193,578,046**	**189,493,713**	**0**	**0**
21. Patronage Capital & Operating Margins (1 minus 20)	**2,301,101**	**3,058,233**	**0**	**0**
22. Non Operating Margins - Interest	160,823	141,935	0	0
23. Allowance for Funds Used During Construction			0	0
24. Income (Loss) from Equity Investments	(123,548)	(119,289)	0	0
25. Non Operating Margins - Other	54,213	7,118	0	0
26. Generation & Transmission Capital Credits	9,989,099	2,329,871	0	0
27. Other Capital Credits & Patronage Dividends	753,619	811,469	0	0
28. Extraordinary Items			0	0
29. Patronage Capital or Margins (21 thru 28)	**13,135,307**	**6,229,337**	**0**	**0**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	722	835	5. Miles Transmission	0	0
2. Services Retired	94	80	6. Miles Distribution Overhead	1,215	1,205
3. Total Services In Place	104,066	104,821	7. Miles Distribution Underground	2,819	2,858
4. Idle Services (Exclude Seasonal)	457	441	**8. Total Miles Energized (5+6+7)**	**4,034**	**4,063**

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT			
		BORROWER NAME	Dakota Electric
		BORROWER DESIGNATION	MN065
		ENDING DATE	12/31/2015

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	274,760,196	29. Memberships	0
2. Construction Work in Progress	3,675,635	30. Patronage Capital	48,070,016
3. Total Utility Plant (1+2)	**278,435,831**	31. Operating Margins - Prior Years	0
4. Accum. Provision for Depreciation and Amort	112,615,047	32. Operating Margins - Current Year	3,058,228
5. Net Utility Plant (3-4)	**165,820,784**	33. Non-Operating Margins	3,171,104
6. Nonutility Property - Net	0	34. Other Margins & Equities	96,676,299
7. Investment in Subsidiary Companies	4,875,012	**35. Total Margins & Equities (29 thru 34)**	**150,975,647**
8. Invest. in Assoc. Org. - Patronage Capital	98,030,276	36. Long-Term Debt CFC (Net)	57,506,512
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	31,355,309
10. Invest in Assoc. Org. - Other - Nongeneral Funds	4,950,903	**38. Total Long-Term Debt (36 + 37)**	**88,861,821**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	694,931
12. Other Investments	0	40. Accumulated Operating Provisions - Asset Retirement Obligations	4,016,000
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**4,710,931**
14. Total Other Property & Investments (6 thru 13)	**107,856,191**	42. Notes Payable	10,700,000
15. Cash-General Funds	536,825	43. Accounts Payable	23,800,562
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	545,453
17. Special Deposits	0	45. Current Maturities Long-Term Debt	6,122,258
18. Temporary Investments	0	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	405,665
20. Accounts Receivable - Net Sales of Energy	17,025,937	48. Other Current & Accrued Liabilities	11,193,808
21. Accounts Receivable - Net Other	418,030	**49. Total Current & Accrued Liabilities (42 thru 48)**	**52,767,746**
22. Renewable Energy Credits	0	50. Deferred Credits	4,242,687
23. Materials & Supplies - Electric and Other	5,228,722	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**301,558,832**
24. Prepayments	1,007,588		
25. Other Current & Accrued Assets	3,407,209	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**27,624,311**	Balance Beginning of Year	47,955,623
27. Deferred Debits	257,546	Amounts Received This Year (Net)	1,940,020
28. Total Assets & Other Debits (5+14+26+27)	**301,558,832**	**TOTAL Contributions-In-Aid-Of-Construction**	**49,895,643**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

Note (1): Part A, line 16 includes $57,712 of interest on capital lease obligations.

Note (2): Part C. line 25 includes $3,372,981 of unbilled revenue not billed to consumers for which kWhs have been consumed.

Note (3): Part C. line 32 is the operating income from page 1, Part A. Line 20 (b) only. Capital credits from page 1, Part A. lines 26(b) and 27(b) are included in Part C. line 33.

Note (4):Part R. line 4 includes only accounts with less than 15KW of demand. In 2004, DEA implemented a new rate structure that combined the accounts with 15KW or greater demand with the large commercial included on line 5.

Note (5):Part K. line 2 in 2015 is the amount written off during the year not including recoveries. The amount net of recoveries is $409,306

Note (6):Part S. Per Bettina Kimmel at CFC, this information is not required. DEA provides it annually to our power supplier, Great River Energy, who consolidates the information for all their members and reports it to the MN Public Utilities Commission. DEA does not calculate or report the information to GRE on an MBTU basis.

Please refer to Dakota Electric's 2015 Audited Financial Statements for additional information.

CFC FORM 7

NATIONAL RURAL UTILITIES
COOPERATIVE FINANCE CORPORATION
FINANCIAL AND STATISTICAL REPORT

BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2015

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	238,442,655	12,467,807	3,871,339	0	**247,039,123**
2	General Plant Subtotal	18,166,428	2,416,550	955,953	0	**19,627,025**
3	Headquarters Plant	7,963,578	137,074	6,604	0	**8,094,048**
4	Intangibles	0	0	0	0	**0**
5	Transmission Plant Subtotal	0	0	0	0	**0**
6	Regional Transmission and Market Operation Plant	0	0	0	0	**0**
7	Production Plant - Steam	0	0	0	0	**0**
8	Production Plant - Nuclear	0	0	0	0	**0**
9	Production Plant - Hydro	0	0	0	0	**0**
10	Production Plant - Other	0	0	0	0	**0**
11	All Other Utility Plant	0	0	0	0	**0**
12	**SUBTOTAL: (1 thru 11)**	**264,572,661**	**15,021,431**	**4,833,896**	**0**	**274,760,196**
13	Construction Work in Progress	5,410,451	(1,734,816)			**3,675,635**
14	**TOTAL UTILITY PLANT (12+13)**	**269,983,112**	**13,286,615**	**4,833,896**	**0**	**278,435,831**

CFC NO LONGER REQUIRES SECTIONS "F", "G", AND "N" DATA
Those sections refer to data on "Analysis of Accumulated Provision for Depreciation" (F),
"Materials and Supplies" (G), "Annual Meeting and Board Data" (N), and "Conservation Data" (P).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	TOTAL
		Power Supplier (a)	Major Event (b)	Planned (c)	All Other (d)	(e)
1.	Present Year	0.00	9.47	1.89	16.51	**27.87**
2.	Five-Year Average	5.55	11.27	1.45	21.79	**40.06**

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	195	4. Payroll - Expensed	12,281,254
2.	Employee - Hours Worked - Regular Time	407,556	5. Payroll - Capitalized	2,297,392
3.	Employee - Hours Worked - Overtime	7,209	6. Payroll - Other	2,095,825

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1.	General Retirement	2,109,588	23,551,049
2.	Special Retirements	851,883	13,324,074
3.	**Total Retirements (1+2)**	**2,961,471**	**36,875,123**
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5.	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric Systen	414,921	
6.	**Total Cash Received (4+5)**	**414,921**	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1. Amount Due Over 60 Days:	1,567,351
2. Amount Written Off During Year:	568,527

NATIONAL RURAL UTILITIES
COOPERATIVE FINANCE CORPORATION
FINANCIAL AND STATISTICAL REPORT

BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2015

PART L. KWH PURCHASED AND TOTAL COST

	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST: WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Great River Energy			0 None	1,841,522,585	140,894,344	7.65	0	0	Comments
2	Great River Energy		Wellspring	1 Wind	8,333,100	670,895	8.05	0	0	Comments
3				0 None	0	0	0.00	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5				0 None	0	0	0.00	0	0	Comments
6				0 None	0	0	0.00	0	0	Comments
7				0 None	0	0	0.00	0	0	Comments
8				0 None	0	0	0.00	0	0	Comments
9				0 None	0	0	0.00	0	0	Comments
10				0 None	0	0	0.00	0	0	Comments
11				0 None	0	0	0.00	0	0	Comments
12				0 None	0	0	0.00	0	0	Comments
13				0 None	0	0	0.00	0	0	Comments
14				0 None	0	0	0.00	0	0	Comments
15				0 None	0	0	0.00	0	0	Comments
16				0 None	0	0	0.00	0	0	Comments
17				0 None	0	0	0.00	0	0	Comments
18				0 None	0	0	0.00	0	0	Comments
19				0 None	0	0	0.00	0	0	Comments
20				0 None	0	0	0.00	0	0	Comments
21	**TOTALS**				**1,849,855,685**	**141,565,239**	**7.65**	**0**	**0**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1	
2	
3	
4	
5	
6	
7	
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9	
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11	
12	
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CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.			$0
2.			$0
3.		TOTAL	$0

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	PRINCIPAL (b)	TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	54,129,539	3,091,138	3,214,842	6,305,980	
2	NCSC	0	0	0	0	
3	Farmer Mac	6,866,692	290,686	439,107	729,793	
4	CoBank	33,987,848	1,137,708	2,056,356	3,194,064	
5		0	0	0	0	
6		0	0	0	0	
7		0	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10	Principal Payments Received from Ultimate Recipients of IRP Loans			0		
11	Principal Payments Received from Ultimate Recipients of REDL Loans			0		
12	**TOTAL (Sum of 1 thru 9)**	**$94,984,079**	**$4,519,532**	**$5,710,305**	**$10,229,837**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

PART R. POWER REQUIREMENTS DATA BASE

CLASSIFICATION	CONSUMER, SALES, AND REVENUE DATA	JANUARY CONSUMERS (a)	DECEMBER CONSUMERS (b)	AVERAGE CONSUMERS (c)	TOTAL KWH SALES AND REVENUE (d)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	95,928	96,516	96,222	
	b. KWH Sold				883,022,355
	c. Revenue				110,354,109
2. Residential Sales - Seasonal	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
3. Irrigation Sales	a. No. Consumers Served	380	391	386	
	b. KWH Sold				6,092,986
	c. Revenue				816,562
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	4,366	4,352	4,359	
	b. KWH Sold				45,180,798
	c. Revenue				5,615,887
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	2,773	2,834	2,804	
	b. KWH Sold				847,563,547
	c. Revenue				72,578,730
6. Public Street & Highway Lighting	a. No. Consumers Served	222	222	222	
	b. KWH Sold				10,455,057
	c. Revenue				2,006,874
7. Other Sales to Public Authority	a. No. Consumers Served	65	65	65	
	b. KWH Sold				0
	c. Revenue				3,900
8. Sales for Resales-RUS Borrowers	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		**103,734**	**104,380**	**104,057**	0
11. TOTAL KWH Sold (lines 1b thru 9b)					**1,792,314,743**
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					**191,376,062**
13. Transmission Revenue					0
14. Other Electric Revenue					1,175,884
15. KWH - Own Use					2,045,275
16. TOTAL KWH Purchased					1,849,855,685
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					141,565,239
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)					408,662
	○ None	○ Non-coincident	◉ Coincident		

CFC FORM 7

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2015

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	0	0	0	0	0
2.	Residential Sales - Seasonal	0	0	0	0	0	0
3.	Irrigation Sales	0	0	0	0	0	0
4.	Comm. and Ind. 1000 KVA or Less	0	0	0	0	0	0
5.	Comm. and Ind. Over 1000 KVA	0	0	0	0	0	0
6.	Public Street and Highway Lighting	0	0	0	0	0	0
7.	Other Sales to Public Authorities	0	0	0	0	0	0
8.	Sales for Resales - RUS Borrowers	0	0	0	0	0	0
9.	Sales for Resales - Other	0	0	0	0	0	0
10.	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

(All investments refer to your most recent CFC Loan Agreement)

7a - PART 1 - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2.	**INVESTMENTS IN ASSOCIATED ORGANIZATIONS**			
5	Capital Term Certificates and Member Capital Securities		4,838,374	
6	Patronage Capital GRE		92,690,746	
7	Patronage Capital NRUCFC		3,930,487	
8	Other	6,396,584		
	Subtotal (Line 5 thru 8)	**6,396,584**	**101,459,607**	**0**
3.	**INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS**			
9				
10				
11				
12				
	Subtotal (Line 9 thru 12)	**0**	**0**	**0**
4.	**OTHER INVESTMENTS**			
13				
14				
15				
16				
	Subtotal (Line 13 thru 16)	**0**	**0**	**0**
5.	**SPECIAL FUNDS**			
17				
18				
19				
20				
	Subtotal (Line 17 thru 20)	**0**	**0**	**0**
6.	**CASH - GENERAL**			
21	Anchor Bank-Farmington	110,872	250,000	
22	Wells Fargo	0	175,445	
23	Petty Cash	508	0	
24				
	Subtotal (Line 21 thru 24)	**111,380**	**425,445**	**0**
7.	**SPECIAL DEPOSITS**			
25				
26				
27				
28				
	Subtotal (Line 25 thru 28)	**0**	**0**	**0**
8.	**TEMPORARY INVESTMENTS**			
29				
30				
31				
32				
	Subtotal (Line 29 thru 32)	**0**	**0**	**0**
9.	**ACCOUNT & NOTES RECEIVABLE - NET**			
33	Accounts Receivable - Non Electric Billing	346,850		
34	Accounts Receivable - Other	71,180		
35				
36				
	Subtotal (Line 33 thru 36)	**418,030**	**0**	**0**
10.	**COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED**			
37				
38				
39				
40				
	Subtotal (Line 37 thru 40)	**0**	**0**	**0**
	Total	**6,925,994**	**101,885,052**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2015

(All investments refer to your most recent CFC Loan Agreement)

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		**6,925,994**
2	LARGER OF (a) OR (b)		**75,487,824**
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	**41,765,375**	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	**75,487,824**	

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric Association
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION	BALANCE CHECK RESULTS	AUTHORIZATION CHOICES
We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.	0 Needs Attention	A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA? YES NO
[redacted] 3/27/17 Signature of Office Manager or Accountant — Date	0 Please Review	
[redacted] 3/27/17 Signature of Manager — Date	21 Matches	B. Will you authorize CFC to share your data with other cooperatives? YES NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	192,551,946	201,585,762	0	0
2. Power Production Expense	0		0	0
3. Cost of Purchased Power	141,565,239	148,623,624	0	0
4. Transmission Expense	0		0	0
5. Regional Market Operations Expense	0		0	0
6. Distribution Expense - Operation	6,871,777	6,720,766	0	0
7. Distribution Expense - Maintenance	5,653,587	5,742,935	0	0
8. Consumer Accounts Expense	4,743,770	3,977,008	0	0
9. Customer Service and Informational Expense	3,347,544	3,919,789	0	0
10. Sales Expense			0	0
11. Administrative and General Expense	10,428,717	10,503,325	0	0
12. Total Operation & Maintenance Expense (2 thru 11)	**172,610,634**	**179,487,447**	**0**	**0**
13. Depreciation & Amortization Expense	8,716,070	8,850,603	0	0
14. Tax Expense - Property & Gross Receipts	3,443,074	3,597,538	0	0
15. Tax Expense - Other			0	0
16. Interest on Long-Term Debt	4,524,806	4,169,404	0	0
17. Interest Charged to Construction (Credit)		0	0	0
18. Interest Expense - Other	279,391	259,115	0	0
19. Other Deductions	(80,262)	(37,218)	0	0
20. Total Cost of Electric Service (12 thru 19)	**189,493,713**	**196,326,889**	**0**	**0**
21. Patronage Capital & Operating Margins (1 minus 20)	**3,058,233**	**5,258,873**	**0**	**0**
22. Non Operating Margins - Interest	141,935	166,539	0	0
23. Allowance for Funds Used During Construction		0	0	0
24. Income (Loss) from Equity Investments	(119,289)	(114,978)	0	0
25. Non Operating Margins - Other	7,118	(38,499)	0	0
26. Generation & Transmission Capital Credits	2,329,871	7,347,424	0	0
27. Other Capital Credits & Patronage Dividends	811,469	869,880	0	0
28. Extraordinary Items		0	0	0
29. Patronage Capital or Margins (21 thru 28)	**6,229,337**	**13,489,239**	**0**	**0**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	835	1,159	5. Miles Transmission	0	0
2. Services Retired	80	113	6. Miles Distribution Overhead	1,205	1,197
3. Total Services In Place	104,821	105,867	7. Miles Distribution Underground	2,858	2898
4. Idle Services (Exclude Seasonal)	441	386	**8. Total Miles Energized (5+6+7)**	**4,063**	**4,095**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT			
		BORROWER NAME	Dakota Electric
		BORROWER DESIGNATION	MN065
		ENDING DATE	12/31/2016

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	280,981,520	29. Memberships	0
2. Construction Work in Progress	5,008,823	30. Patronage Capital	47,557,568
3. Total Utility Plant (1+2)	**285,990,343**	31. Operating Margins - Prior Years	0
4. Accum. Provision for Depreciation and Amort	117,061,473	32. Operating Margins - Current Year	5,258,876
5. Net Utility Plant (3-4)	**168,928,870**	33. Non-Operating Margins	8,230,366
6. Nonutility Property - Net	0	34. Other Margins & Equities	100,247,381
7. Investment in Subsidiary Companies	4,760,034	**35. Total Margins & Equities (29 thru 34)**	**161,294,191**
8. Invest. in Assoc. Org. - Patronage Capital	105,707,320	36. Long-Term Debt CFC (Net)	51,714,119
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	35,292,425
10. Invest in Assoc. Org. - Other - Nongeneral Funds	4,685,675	**38. Total Long-Term Debt (36 + 37)**	**87,006,544**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	591,885
12. Other Investments	0	40. Accumulated Operating Provisions - Asset Retirement Obligations	3,925,000
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**4,516,885**
14. Total Other Property & Investments (6 thru 13)	**115,153,029**	42. Notes Payable	12,500,000
15. Cash-General Funds	988,866	43. Accounts Payable	25,031,964
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	537,197
17. Special Deposits	0	45. Current Maturities Long-Term Debt	6,872,297
18. Temporary Investments	0	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	355,935
20. Accounts Receivable - Net Sales of Energy	18,956,146	48. Other Current & Accrued Liabilities	11,934,854
21. Accounts Receivable - Net Other	556,998	**49. Total Current & Accrued Liabilities (42 thru 48)**	**57,232,247**
22. Renewable Energy Credits	0	50. Deferred Credits	3,817,886
23. Materials & Supplies - Electric and Other	4,069,740	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**313,867,753**
24. Prepayments	1,018,547		
25. Other Current & Accrued Assets	3,181,369	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**28,771,666**	Balance Beginning of Year	49,895,643
27. Deferred Debits	1,014,188	Amounts Received This Year (Net)	1,855,364
28. Total Assets & Other Debits (5+14+26+27)	**313,867,753**	**TOTAL Contributions-In-Aid-Of-Construction**	**51,751,007**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

Note (1): Part A, line 16 includes $56,082 of interest on capital lease obligations.

Note (2): Part C. line 25 includes $3,122,141of unbilled revenue not billed to consumers for which kWhs have been consumed.

Note (3): Part C. line 32 is the operating income from page 1, Part A. Line 20 (b) only. Capital credits from page 1, Part A. lines 26(b) and 27(b) are included in Part C. line 33.

Note (4):Part R. line 4 includes only accounts with less than 15KW of demand. In 2004, DEA implemented a new rate structure that combined the accounts with 15KW or greater demand with the large commercial included on line 5.

Note (5):Part K. line 2 in 2016 is the amount written off during the year not including recoveries. The amount net of recoveries is $294,284

Note (6):Part S. Per Bettina Kimmel at CFC, this information is not required. DEA provides it annually to our power supplier, Great River Energy, who consolidates the information for all their members and reports it to the MN Public Utilities Commission. DEA does not calculate or report the information to GRE on an MBTU basis.

Please refer to Dakota Electric's 2016 Audited Financial Statements for additional information.

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	247,039,123	8,026,549	2,785,233	0	**252,280,439**
2	General Plant Subtotal	19,627,025	2,331,596	1,514,258	16,388	**20,460,751**
3	Headquarters Plant	8,094,048	256,327	93,657	(16,388)	**8,240,330**
4	Intangibles	0	0	0	0	**0**
5	Transmission Plant Subtotal	0	0	0	0	**0**
6	Regional Transmission and Market Operation Plant	0	0	0	0	**0**
7	Production Plant - Steam	0	0	0	0	**0**
8	Production Plant - Nuclear	0	0	0	0	**0**
9	Production Plant - Hydro	0	0	0	0	**0**
10	Production Plant - Other	0	0	0	0	**0**
11	All Other Utility Plant	0	0	0	0	**0**
12	**SUBTOTAL: (1 thru 11)**	**274,760,196**	**10,614,472**	**4,393,148**	**0**	**280,981,520**
13	Construction Work in Progress	3,675,635	1,333,188			**5,008,823**
14	**TOTAL UTILITY PLANT (12+13)**	**278,435,831**	**11,947,660**	**4,393,148**	**0**	**285,990,343**

CFC NO LONGER REQUIRES SECTIONS "F", "G", AND "N" DATA
Those sections refer to data on "Analysis of Accumulated Provision for Depreciation" (F),
"Materials and Supplies" (G), "Annual Meeting and Board Data" (N), and "Conservation Data" (P).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	TOTAL
		Power Supplier (a)	Major Event (b)	Planned (c)	All Other (d)	(e)
1.	Present Year	0.00	11.91	2.00	18.91	**32.82**
2.	Five-Year Average	5.12	12.19	1.60	21.75	**40.66**

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	193	4.	Payroll - Expensed	12,604,232
2.	Employee - Hours Worked - Regular Time	413,706	5.	Payroll - Capitalized	2,404,264
3.	Employee - Hours Worked - Overtime	8,434	6.	Payroll - Other	2,016,259

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1.	General Retirement	2,572,278	26,123,327
2.	Special Retirements	945,926	14,270,000
3.	**Total Retirements (1+2)**	**3,518,204**	**40,393,327**
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5.	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric Systen	472,664	
6.	**Total Cash Received (4+5)**	**472,664**	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1. Amount Due Over 60 Days:	1,895,088
2. Amount Written Off During Year:	477,402

NATIONAL RURAL UTILITIES
COOPERATIVE FINANCE CORPORATION
FINANCIAL AND STATISTICAL REPORT

BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2016

PART L. KWH PURCHASED AND TOTAL COST

								INCLUDED IN TOTAL COST		
	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	FUEL COST ADJUSTMENT (h)	WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Great River Energy			0 None	1,864,069,031	147,901,753	7.93	0	0	Comments
2	Great River Energy		Wellspring	1 Wind	8,580,100	715,096	8.33	0	0	Comments
3	Great River Energy		Wellspring	2 Sun	68,200	6,775	9.93	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5				0 None	0	0	0.00	0	0	Comments
6				0 None	0	0	0.00	0	0	Comments
7				0 None	0	0	0.00	0	0	Comments
8				0 None	0	0	0.00	0	0	Comments
9				0 None	0	0	0.00	0	0	Comments
10				0 None	0	0	0.00	0	0	Comments
11				0 None	0	0	0.00	0	0	Comments
12				0 None	0	0	0.00	0	0	Comments
13				0 None	0	0	0.00	0	0	Comments
14				0 None	0	0	0.00	0	0	Comments
15				0 None	0	0	0.00	0	0	Comments
16				0 None	0	0	0.00	0	0	Comments
17				0 None	0	0	0.00	0	0	Comments
18				0 None	0	0	0.00	0	0	Comments
19				0 None	0	0	0.00	0	0	Comments
20				0 None	0	0	0.00	0	0	Comments
21	**TOTALS**				**1,872,717,331**	**148,623,624**	**7.94**	**0**	**0**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1	
2	
3	
4	
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CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.			$0
2.			$0
3.		TOTAL	$0

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	PRINCIPAL (b)	TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	49,413,388	2,459,897	3,100,546	5,560,443	
2	NCSC	0	0	0	0	
3	Farmer Mac	6,410,144	273,245	456,548	729,793	
4	CoBank	38,055,309	1,451,952	2,632,539	4,084,491	
5		0	0	0	0	
6		0	0	0	0	
7		0	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10	Principal Payments Received from Ultimate Recipients of IRP Loans			0		
11	Principal Payments Received from Ultimate Recipients of REDL Loans			0		
12	**TOTAL (Sum of 1 thru 9)**	**$93,878,841**	**$4,185,094**	**$6,189,633**	**$10,374,727**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

PART R. POWER REQUIREMENTS DATA BASE

CLASSIFICATION	CONSUMER, SALES, AND REVENUE DATA	JANUARY CONSUMERS (a)	DECEMBER CONSUMERS (b)	AVERAGE CONSUMERS (c)	TOTAL KWH SALES AND REVENUE (d)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	96,588	97,493	97,041	
	b. KWH Sold				898,634,906
	c. Revenue				116,849,882
2. Residential Sales - Seasonal	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
3. Irrigation Sales	a. No. Consumers Served	391	392	392	
	b. KWH Sold				7,002,123
	c. Revenue				920,785
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	4,358	4,431	4,395	
	b. KWH Sold				43,999,716
	c. Revenue				5,709,677
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	2,839	2,888	2,864	
	b. KWH Sold				861,101,737
	c. Revenue				74,518,695
6. Public Street & Highway Lighting	a. No. Consumers Served	222	211	217	
	b. KWH Sold				11,235,644
	c. Revenue				2,042,232
7. Other Sales to Public Authority	a. No. Consumers Served	65	66	66	
	b. KWH Sold				0
	c. Revenue				3,900
8. Sales for Resales-RUS Borrowers	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		**104,463**	**105,481**	**104,972**	
11. TOTAL KWH Sold (lines 1b thru 9b)					**1,821,974,126**
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					**200,045,171**
13. Transmission Revenue					0
14. Other Electric Revenue					1,540,591
15. KWH - Own Use					2,052,552
16. TOTAL KWH Purchased					1,872,717,331
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					148,623,624
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)					379,489
	○ None	○ Non-coincident	◉ Coincident		

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	
BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2016

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	0	0	0	0	0
2.	Residential Sales - Seasonal	0	0	0	0	0	0
3.	Irrigation Sales	0	0	0	0	0	0
4.	Comm. and Ind. 1000 KVA or Less	0	0	0	0	0	0
5.	Comm. and Ind. Over 1000 KVA	0	0	0	0	0	0
6.	Public Street and Highway Lighting	0	0	0	0	0	0
7.	Other Sales to Public Authorities	0	0	0	0	0	0
8.	Sales for Resales - RUS Borrowers	0	0	0	0	0	0
9.	Sales for Resales - Other	0	0	0	0	0	0
10.	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

(All investments refer to your most recent CFC Loan Agreement)

7a - PART 1 - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2. INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
5	Capital Term Certificates and Member Capital Securities	0	4,573,145	0
6	Patronage Capital GRE	0	100,038,169	0
7	Patronage Capital - NRUCFC	0	4,055,031	0
8	Other	6,486,684	0	0
	Subtotal (Line 5 thru 8)	**6,486,684**	**108,666,345**	**0**
3. INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
9		0	0	0
10		0	0	0
11		0	0	0
12		0	0	0
	Subtotal (Line 9 thru 12)	**0**	**0**	**0**
4. OTHER INVESTMENTS				
13		0	0	0
14		0	0	0
15		0	0	0
16		0	0	0
	Subtotal (Line 13 thru 16)	**0**	**0**	**0**
5. SPECIAL FUNDS				
17		0	0	0
18		0	0	0
19		0	0	0
20		0	0	0
	Subtotal (Line 17 thru 20)	**0**	**0**	**0**
6. CASH - GENERAL				
21	Anchor Bank-Farmington	597,622	250,000	0
22	Wells Fargo	0	140,736	0
23	Petty Cash	508	0	0
24		0	0	0
	Subtotal (Line 21 thru 24)	**598,130**	**390,736**	**0**
7. SPECIAL DEPOSITS				
25		0	0	0
26		0	0	0
27		0	0	0
28		0	0	0
	Subtotal (Line 25 thru 28)	**0**	**0**	**0**
8. TEMPORARY INVESTMENTS				
29		0	0	0
30		0	0	0
31		0	0	0
32		0	0	0
	Subtotal (Line 29 thru 32)	**0**	**0**	**0**
9. ACCOUNT & NOTES RECEIVABLE - NET				
33	Accounts Receivable - Non Electric Billing	516,947	0	0
34	Accounts Receivable - Other	40,051	0	0
35		0	0	0
36		0	0	0
	Subtotal (Line 33 thru 36)	**556,998**	**0**	**0**
10. COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED				
37		0	0	0
38		0	0	0
39		0	0	0
40		0	0	0
	Subtotal (Line 37 thru 40)	**0**	**0**	**0**
	Total	**7,641,812**	**109,057,081**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2016

(All investments refer to your most recent CFC Loan Agreement)

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		**7,641,812**
2	LARGER OF (a) OR (b)		**80,647,096**
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	**42,898,551**	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	**80,647,096**	

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric Association
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

[redacted] 3/14/18
Signature of Office Manager or Accountant — Date

[redacted] 3/14/18
Signature of Manager — Date

BALANCE CHECK RESULTS

0 Needs Attention
0 Please Review
21 Matches

AUTHORIZATION CHOICES

A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA?
YES NO

B. Will you authorize CFC to share your data with other cooperatives?
YES NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	201,585,762	201,226,992	0	0
2. Power Production Expense			0	0
3. Cost of Purchased Power	148,623,624	147,874,758	0	0
4. Transmission Expense			0	0
5. Regional Market Operations Expense			0	0
6. Distribution Expense - Operation	6,720,766	6,584,595	0	0
7. Distribution Expense - Maintenance	5,742,935	5,812,250	0	0
8. Consumer Accounts Expense	3,977,008	4,360,768	0	0
9. Customer Service and Informational Expense	3,919,789	4,099,386	0	0
10. Sales Expense			0	0
11. Administrative and General Expense	10,503,325	11,341,864	0	0
12. Total Operation & Maintenance Expense (2 thru 11)	**179,487,447**	**180,073,621**	**0**	**0**
13. Depreciation & Amortization Expense	8,850,603	9,491,587	0	0
14. Tax Expense - Property & Gross Receipts	3,597,538	3,609,198	0	0
15. Tax Expense - Other			0	0
16. Interest on Long-Term Debt	4,169,404	3,747,120	0	0
17. Interest Charged to Construction (Credit)	0	0	0	0
18. Interest Expense - Other	259,115	447,606	0	0
19. Other Deductions	(37,218)	(22,241)	0	0
20. Total Cost of Electric Service (12 thru 19)	**196,326,889**	**197,346,891**	**0**	**0**
21. Patronage Capital & Operating Margins (1 minus 20)	**5,258,873**	**3,880,101**	**0**	**0**
22. Non Operating Margins - Interest	166,539	189,286	0	0
23. Allowance for Funds Used During Construction	0	0	0	0
24. Income (Loss) from Equity Investments	(114,978)	(158,851)	0	0
25. Non Operating Margins - Other	(38,499)	67,576	0	0
26. Generation & Transmission Capital Credits	7,347,424	6,403,850	0	0
27. Other Capital Credits & Patronage Dividends	869,880	761,693	0	0
28. Extraordinary Items	0	0	0	0
29. Patronage Capital or Margins (21 thru 28)	**13,489,239**	**11,143,655**	**0**	0

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	1,159	1,407	5. Miles Transmission	0	0
2. Services Retired	113	73	6. Miles Distribution Overhead	1,197	1,195
3. Total Services In Place	105,867	107,201	7. Miles Distribution Underground	2,898	2,937
4. Idle Services (Exclude Seasonal)	386	366	**8. Total Miles Energized (5+6+7)**	**4,095**	**4,132**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT			
		BORROWER NAME	Dakota Electric
		BORROWER DESIGNATION	MN065
		ENDING DATE	12/31/2017

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	291,219,850	29. Memberships	0
2. Construction Work in Progress	5,113,969	30. Patronage Capital	49,104,028
3. Total Utility Plant (1+2)	**296,333,819**	31. Operating Margins - Prior Years	0
4. Accum. Provision for Depreciation and Amort	121,824,590	32. Operating Margins - Current Year	3,880,101
5. Net Utility Plant (3-4)	**174,509,229**	33. Non-Operating Margins	7,263,554
6. Nonutility Property - Net	0	34. Other Margins & Equities	108,951,375
7. Investment in Subsidiary Companies	4,601,183	**35. Total Margins & Equities (29 thru 34)**	**169,199,058**
8. Invest. in Assoc. Org. - Patronage Capital	112,381,152	36. Long-Term Debt CFC (Net)	57,457,414
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	32,433,190
10. Invest in Assoc. Org. - Other - Nongeneral Funds	4,627,795	**38. Total Long-Term Debt (36 + 37)**	**89,890,604**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	767,576
12. Other Investments	0	40. Accumulated Operating Provisions - Asset Retirement Obligations	4,207,000
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**4,974,576**
14. Total Other Property & Investments (6 thru 13)	**121,610,130**	42. Notes Payable	13,600,000
15. Cash-General Funds	142,650	43. Accounts Payable	25,080,492
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	528,907
17. Special Deposits	0	45. Current Maturities Long-Term Debt	7,178,093
18. Temporary Investments	0	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	517,185
20. Accounts Receivable - Net Sales of Energy	19,940,989	48. Other Current & Accrued Liabilities	12,607,375
21. Accounts Receivable - Net Other	440,745	**49. Total Current & Accrued Liabilities (42 thru 48)**	**59,512,052**
22. Renewable Energy Credits	0	50. Deferred Credits	4,812,096
23. Materials & Supplies - Electric and Other	4,472,687	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**328,388,386**
24. Prepayments	976,797		
25. Other Current & Accrued Assets	5,194,535	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**31,168,403**	Balance Beginning of Year	51,751,007
27. Deferred Debits	1,100,624	Amounts Received This Year (Net)	1,575,275
28. Total Assets & Other Debits (5+14+26+27)	**328,388,386**	**TOTAL Contributions-In-Aid-Of-Construction**	**53,326,282**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

Note (1): Part A, line 16 includes $59,063 of interest on capital lease obligations.

Note (2): Part C. line 25 includes $5,160,307of unbilled revenue not billed to consumers for which kWhs have been consumed.

Note (3): Part C. line 32 is the operating income from page 1, Part A. Line 20 (b) only. Capital credits from page 1, Part A. lines 26(b) and 27(b) are included in Part C. line 33.

Note (4):Part R. line 4 includes only accounts with less than 15KW of demand. In 2004, DEA implemented a new rate structure that combined the accounts with 15KW or greater demand with the large commercial included on line 5.

Note (5):Part K. line 2 in 2017 is the amount written off during the year not including recoveries. The amount net of recoveries is $403,842

Note (6):Part S. Per Bettina Kimmel at CFC, this information is not required. DEA provides it annually to our power supplier, Great River Energy, who consolidates the information for all their members and reports it to the MN Public Utilities Commission. DEA does not calculate or report the information to GRE on an MBTU basis.

Note (7): Part R. In April 2017, the unbilled revenue estimate was increased, unbilled kWh estimate was increased, and the power cost adjustment liability was increased due to an adjustment to the estimated line loss percentage used in the unbilled calculation.
Line loss excluding the unbilled kWh adjustment is 2.60%

Please refer to Dakota Electric's 2017 Audited Financial Statements for additonal information.

CFC FORM 7

NATIONAL RURAL UTILITIES
COOPERATIVE FINANCE CORPORATION
FINANCIAL AND STATISTICAL REPORT

BORROWER NAME	Dakota Electric
BORROWER DESIGNATION	MN065
ENDING DATE	12/31/2017

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	252,280,439	12,445,146	3,119,802	0	**261,605,783**
2	General Plant Subtotal	20,460,751	2,149,807	1,481,477	0	**21,129,081**
3	Headquarters Plant	8,240,330	267,556	22,900	0	**8,484,986**
4	Intangibles	0	0	0	0	**0**
5	Transmission Plant Subtotal	0	0	0	0	**0**
6	Regional Transmission and Market Operation Plant	0	0	0	0	**0**
7	Production Plant - Steam	0	0	0	0	**0**
8	Production Plant - Nuclear	0	0	0	0	**0**
9	Production Plant - Hydro	0	0	0	0	**0**
10	Production Plant - Other	0	0	0	0	**0**
11	All Other Utility Plant	0	0	0	0	**0**
12	**SUBTOTAL: (1 thru 11)**	**280,981,520**	**14,862,509**	**4,624,179**	**0**	**291,219,850**
13	Construction Work in Progress	5,008,823	105,146			**5,113,969**
14	**TOTAL UTILITY PLANT (12+13)**	**285,990,343**	**14,967,655**	**4,624,179**	**0**	**296,333,819**

CFC NO LONGER REQUIRES SECTIONS "F", "G", AND "N" DATA
Those sections refer to data on "Analysis of Accumulated Provision for Depreciation" (F),
"Materials and Supplies" (G), "Annual Meeting and Board Data" (N), and "Conservation Data" (P).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg. Minutes per Consumer by Cause: Power Supplier (a)	Avg. Minutes per Consumer by Cause: Major Event (b)	Avg. Minutes per Consumer by Cause: Planned (c)	Avg. Minutes per Consumer by Cause: All Other (d)	TOTAL (e)
1.	Present Year	0.20	3.57	2.55	14.47	**20.79**
2.	Five-Year Average	0.84	8.09	1.87	19.77	**30.57**

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	193	4. Payroll - Expensed	12,812,891
2.	Employee - Hours Worked - Regular Time	416,388	5. Payroll - Capitalized	2,656,804
3.	Employee - Hours Worked - Overtime	7,754	6. Payroll - Other	2,148,528

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1.	General Retirement	2,661,052	28,784,378
2.	Special Retirements	974,486	15,244,486
3.	**Total Retirements (1+2)**	**3,635,538**	**44,028,864**
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5.	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric Systen	408,189	
6.	**Total Cash Received (4+5)**	**408,189**	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1. Amount Due Over 60 Days: 1,531,135

2. Amount Written Off During Year: 552,520

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

PART L. KWH PURCHASED AND TOTAL COST

	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST: WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Great River Energy			0 None	1,831,793,527	147,838,402	8.07	0	0	Comments
2	Great River Energy		Wellspring	1 Wind	8,490,600	33,962	0.40	0	0	Comments
3	Great River Energy		Wellspring	2 Sun	119,700	2,394	2.00	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5				0 None	0	0	0.00	0	0	Comments
6				0 None	0	0	0.00	0	0	Comments
7				0 None	0	0	0.00	0	0	Comments
8				0 None	0	0	0.00	0	0	Comments
9				0 None	0	0	0.00	0	0	Comments
10				0 None	0	0	0.00	0	0	Comments
11				0 None	0	0	0.00	0	0	Comments
12				0 None	0	0	0.00	0	0	Comments
13				0 None	0	0	0.00	0	0	Comments
14				0 None	0	0	0.00	0	0	Comments
15				0 None	0	0	0.00	0	0	Comments
16				0 None	0	0	0.00	0	0	Comments
17				0 None	0	0	0.00	0	0	Comments
18				0 None	0	0	0.00	0	0	Comments
19				0 None	0	0	0.00	0	0	Comments
20				0 None	0	0	0.00	0	0	Comments
21	**TOTALS**				**1,840,403,827**	**147,874,758**	**8.03**	**0**	**0**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1	
2	
3	
4	
5	
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CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.			$0
2.			$0
3.		TOTAL	$0

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	PRINCIPAL (b)	TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	55,840,811	2,028,860	3,572,578	5,601,438	
2	NCSC	0	0	0	0	
3	Farmer Mac	5,935,461	255,111	474,683	729,794	
4	CoBank	35,292,425	1,385,236	2,762,884	4,148,120	
5		0	0	0	0	
6		0	0	0	0	
7		0	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10	Principal Payments Received from Ultimate Recipients of IRP Loans			0		
11	Principal Payments Received from Ultimate Recipients of REDL Loans			0		
12	**TOTAL (Sum of 1 thru 9)**	**$97,068,697**	**$3,669,207**	**$6,810,145**	**$10,479,352**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

PART R. POWER REQUIREMENTS DATA BASE

CLASSIFICATION	CONSUMER, SALES, AND REVENUE DATA	JANUARY CONSUMERS (a)	DECEMBER CONSUMERS (b)	AVERAGE CONSUMERS (c)	TOTAL KWH SALES AND REVENUE (d)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	97,553	98,749	98,151	
	b. KWH Sold				895,737,914
	c. Revenue				115,416,501
2. Residential Sales - Seasonal	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
3. Irrigation Sales	a. No. Consumers Served	392	390	391	
	b. KWH Sold				7,997,681
	c. Revenue				1,009,141
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	4,426	4,475	4,451	
	b. KWH Sold				44,001,794
	c. Revenue				5,770,215
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	2,901	2,943	2,922	
	b. KWH Sold				861,533,353
	c. Revenue				75,108,588
6. Public Street & Highway Lighting	a. No. Consumers Served	211	212	212	
	b. KWH Sold				11,218,041
	c. Revenue				2,074,506
7. Other Sales to Public Authority	a. No. Consumers Served	66	66	66	
	b. KWH Sold				0
	c. Revenue				3,900
8. Sales for Resales-RUS Borrowers	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		**105,549**	**106,835**	**106,192**	0
11. TOTAL KWH Sold (lines 1b thru 9b)					**1,820,488,783**
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					**199,382,851**
13. Transmission Revenue					0
14. Other Electric Revenue					1,844,141
15. KWH - Own Use					2,064,546
16. TOTAL KWH Purchased					1,840,403,827
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					147,874,758
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)					410,169
	○ None	○ Non-coincident	◉ Coincident		

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	0	0	0	0	0
2.	Residential Sales - Seasonal	0	0	0	0	0	0
3.	Irrigation Sales	0	0	0	0	0	0
4.	Comm. and Ind. 1000 KVA or Less	0	0	0	0	0	0
5.	Comm. and Ind. Over 1000 KVA	0	0	0	0	0	0
6.	Public Street and Highway Lighting	0	0	0	0	0	0
7.	Other Sales to Public Authorities	0	0	0	0	0	0
8.	Sales for Resales - RUS Borrowers	0	0	0	0	0	0
9.	Sales for Resales - Other	0	0	0	0	0	0
10.	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

(All investments refer to your most recent CFC Loan Agreement)

7a - PART 1 - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2. INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
5	Capital Term Certificates and Member Capital Securities		4,515,265	
6	Patronage Capital GRE		106,442,020	
7	Patronage Capital - NRUCFC		4,155,327	
8	Other	6,497,518		
	Subtotal (Line 5 thru 8)	**6,497,518**	**115,112,612**	**0**
3. INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
9				
10				
11				
12				
	Subtotal (Line 9 thru 12)	**0**	**0**	**0**
4. OTHER INVESTMENTS				
13				
14				
15				
16				
	Subtotal (Line 13 thru 16)	**0**	**0**	**0**
5. SPECIAL FUNDS				
17				
18				
19				
20				
	Subtotal (Line 17 thru 20)	**0**	**0**	**0**
6. CASH - GENERAL				
21	Anchor Bank-Farmington	0	440	
22	Wells Fargo	0	141,702	
23	Petty Cash	508	0	
24				
	Subtotal (Line 21 thru 24)	**508**	**142,142**	**0**
7. SPECIAL DEPOSITS				
25				
26				
27				
28				
	Subtotal (Line 25 thru 28)	**0**	**0**	**0**
8. TEMPORARY INVESTMENTS				
29				
30				
31				
32				
	Subtotal (Line 29 thru 32)	**0**	**0**	**0**
9. ACCOUNT & NOTES RECEIVABLE - NET				
33	Accounts Receivable - Non Electric Billing	256,082		
34	Accounts Receivable - Other	184,663		
35				
36				
	Subtotal (Line 33 thru 36)	**440,745**	**0**	**0**
10. COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED				
37				
38				
39				
40				
	Subtotal (Line 37 thru 40)	**0**	**0**	**0**
	Total	**6,938,771**	**115,254,754**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2017

(All investments refer to your most recent CFC Loan Agreement)

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		**6,938,771**
2	LARGER OF (a) OR (b)		**84,599,529**
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	**44,450,073**	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	**84,599,529**	

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric Association
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2018

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

CERTIFICATION	BALANCE CHECK RESULTS	AUTHORIZATION
We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.	0 Needs Attention 0 Please Review 22 Matches	NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA? (•) YES ( ) NO
[redacted] 3/13/19 Signature of Office Manager or Accountant Date [redacted] 3/13/19 Signature of Manager Date		

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	201,226,992	203,138,675	0	0
2. Power Production Expense			0	0
3. Cost of Purchased Power	147,874,758	149,330,034	0	0
4. Transmission Expense			0	0
5. Regional Market Operations Expense			0	0
6. Distribution Expense - Operation	6,584,595	7,277,184	0	0
7. Distribution Expense - Maintenance	5,812,250	6,151,338	0	0
8. Consumer Accounts Expense	4,360,768	5,312,955	0	0
9. Customer Service and Informational Expense	4,099,386	3,585,760	0	0
10. Sales Expense			0	0
11. Administrative and General Expense	11,341,864	11,907,838	0	0
12. Total Operation & Maintenance Expense (2 thru 11)	**180,073,621**	**183,565,109**	**0**	**0**
13. Depreciation & Amortization Expense	9,491,587	10,281,975	0	0
14. Tax Expense - Property & Gross Receipts	3,609,198	3,372,283	0	0
15. Tax Expense - Other	0	0	0	0
16. Interest on Long-Term Debt	3,747,120	3,741,685	0	0
17. Interest Charged to Construction (Credit)	0	0	0	0
18. Interest Expense - Other	447,606	549,008	0	0
19. Other Deductions	(22,241)	6,239	0	0
20. Total Cost of Electric Service (12 thru 19)	**197,346,891**	**201,516,299**	**0**	**0**
21. Patronage Capital & Operating Margins (1 minus 20)	**3,880,101**	**1,622,376**	**0**	**0**
22. Non Operating Margins - Interest	189,286	174,728	0	0
23. Allowance for Funds Used During Construction	0	0	0	0
24. Income (Loss) from Equity Investments	(158,851)	8,227	0	0
25. Non Operating Margins - Other	67,576	110,023	0	0
26. Generation & Transmission Capital Credits	6,403,850	4,311,432	0	0
27. Other Capital Credits & Patronage Dividends	761,693	799,780	0	0
28. Extraordinary Items	0		0	0
29. Patronage Capital or Margins (21 thru 28)	**11,143,655**	**7,026,566**	**0**	**0**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	1,407	1,282	5. Miles Transmission	0	0
2. Services Retired	73	209	6. Miles Distribution Overhead	1,195	1,188
3. Total Services In Place	107,201	108,274	7. Miles Distribution Underground	2,937	2961
4. Idle Services (Exclude Seasonal)	366	300	**8. Total Miles Energized (5+6+7)**	**4,132**	**4,149**

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT			
		BORROWER NAME	Dakota Electric
		BORROWER DESIGNATION	MN065
		ENDING DATE	12/31/2018

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	300,342,133	29. Memberships	0
2. Construction Work in Progress	4,222,209	30. Patronage Capital	49,353,994
3. Total Utility Plant (1+2)	**304,564,342**	31. Operating Margins - Prior Years	0
4. Accum. Provision for Depreciation and Amort	126,121,950	32. Operating Margins - Current Year	1,622,376
5. Net Utility Plant (3-4)	**178,442,392**	33. Non-Operating Margins	5,404,190
6. Nonutility Property - Net	0	34. Other Margins & Equities	116,770,607
7. Investment in Subsidiary Companies	4,609,409	**35. Total Margins & Equities (29 thru 34)**	**173,151,167**
8. Invest. in Assoc. Org. - Patronage Capital	116,936,898	36. Long-Term Debt CFC (Net)	63,986,625
9. Invest. in Assoc. Org. - Other - General Funds	0	37. Long-Term Debt - Other (Net)	29,474,071
10. Invest in Assoc. Org. - Other - Nongeneral Funds	4,118,683	**38. Total Long-Term Debt (36 + 37)**	**93,460,696**
11. Investments in Economic Development Projects	0	39. Obligations Under Capital Leases - Non current	1,379,543
12. Other Investments	0	40. Accumulated Operating Provisions - Asset Retirement Obligations	4,609,000
13. Special Funds	0	**41. Total Other Noncurrent Liabilities (39+40)**	**5,988,543**
14. Total Other Property & Investments (6 thru 13)	**125,664,990**	42. Notes Payable	20,734,355
15. Cash-General Funds	325,778	43. Accounts Payable	22,245,941
16. Cash-Construction Funds-Trustee	0	44. Consumers Deposits	505,101
17. Special Deposits	0	45. Current Maturities Long-Term Debt	6,387,701
18. Temporary Investments	0	46. Current Maturities Long-Term Debt-Economic Dev.	0
19. Notes Receivable - Net	0	47. Current Maturities Capital Leases	512,662
20. Accounts Receivable - Net Sales of Energy	23,990,011	48. Other Current & Accrued Liabilities	12,800,350
21. Accounts Receivable - Net Other	850,182	**49. Total Current & Accrued Liabilities (42 thru 48)**	**63,186,110**
22. Renewable Energy Credits	0	50. Deferred Credits	4,407,261
23. Materials & Supplies - Electric and Other	4,184,242	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**340,193,777**
24. Prepayments	1,314,991		
25. Other Current & Accrued Assets	5,086,132	**ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION**	
26. Total Current & Accrued Assets (15 thru 25)	**35,751,336**	Balance Beginning of Year	53,326,282
27. Deferred Debits	335,059	Amounts Received This Year (Net)	2,190,548
28. Total Assets & Other Debits (5+14+26+27)	**340,193,777**	**TOTAL Contributions-In-Aid-Of-Construction**	**55,516,830**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

Note (1): Part A, line 16 includes $64,846 of interest on capital lease obligations.

Note (2): Part C. line 25 includes $5,051,904 of unbilled revenue not billed to consumers for which kWhs have been consumed.

Note (3): Part C. line 32 is the operating income from page 1, Part A. Line 20 (b) only. Capital credits from page 1, Part A. lines 26(b) and 27(b) are included in Part C. line 33.

Note (4):Part R. line 4 includes only accounts with less than 15KW of demand. In 2004, DEA implemented a new rate structure that combined the accounts with 15KW or greater demand with the large commercial included on line 5.

Note (5):Part K. line 2 in 2018 is the amount written off during the year not including recoveries. The amount net of recoveries is $338,375

Note (6):Part S. Per Bettina Kimmel at CFC, this information is not required. DEA provides it annually to our power supplier, Great River Energy, who consolidates the information for all their members and reports it to the MN Public Utilities Commission. DEA does not calculate or report the information to GRE on an MBTU basis.

Please refer to Dakota Electric's 2018 Audited Financial Statements for additonal information.

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2018

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	261,605,783	9,744,293	3,994,994	0	**267,355,082**
2	General Plant Subtotal	21,129,081	4,627,076	1,451,657	0	**24,304,500**
3	Headquarters Plant	8,484,986	370,501	172,936	0	**8,682,551**
4	Intangibles	0	0	0	0	**0**
5	Transmission Plant Subtotal	0	0	0	0	**0**
6	Regional Transmission and Market Operation Plant	0	0	0	0	**0**
7	Production Plant - Steam	0	0	0	0	**0**
8	Production Plant - Nuclear	0	0	0	0	**0**
9	Production Plant - Hydro	0	0	0	0	**0**
10	Production Plant - Other	0	0	0	0	**0**
11	All Other Utility Plant	0	0	0	0	**0**
12	**SUBTOTAL: (1 thru 11)**	**291,219,850**	**14,741,870**	**5,619,587**	**0**	**300,342,133**
13	Construction Work in Progress	5,113,969	(891,760)			**4,222,209**
14	**TOTAL UTILITY PLANT (12+13)**	**296,333,819**	**13,850,110**	**5,619,587**	**0**	**304,564,342**

CFC NO LONGER REQUIRES SECTIONS "F", "J", AND "M" DATA
Those sections refer to data on "Materials and Supplies" (F), "Energy Efficiency and Conservation Loan Program" (J), and "Annual Meeting and Board Data" (M).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	Avg. Minutes per Consumer by Cause	TOTAL
		Power Supplier (a)	Major Event (b)	Planned (c)	All Other (d)	(e)
1.	Present Year	0.00	10.13	1.22	18.07	**29.42**
2.	Five-Year Average	0.29	7.48	1.82	18.70	**28.29**

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	196	4. Payroll - Expensed	13,584,770
2.	Employee - Hours Worked - Regular Time	422,235	5. Payroll - Capitalized	2,527,608
3.	Employee - Hours Worked - Overtime	9,354	6. Payroll - Other	2,223,363

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1.	General Retirement	2,433,501	31,217,879
2.	Special Retirements	1,204,782	16,449,268
3.	**Total Retirements (1+2)**	**3,638,283**	**47,667,147**
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5.	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric System	468,250	
6.	**Total Cash Received (4+5)**	**468,250**	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1. Amount Due Over 60 Days:	2,324,810
2. Amount Written Off During Year:	429,626

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2018

PART L. KWH PURCHASED AND TOTAL COST

	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST: WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Great River Energy			0 None	1,892,226,617	149,290,724	7.89	0	0	Comments
2	Great River Energy		Wellspring	1 Wind	8,954,600	35,818	0.40	0	0	Comments
3	Great River Energy		Wellspring	2 Sun	174,600	3,492	2.00	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5				0 None	0	0	0.00	0	0	Comments
6				0 None	0	0	0.00	0	0	Comments
7				0 None	0	0	0.00	0	0	Comments
8				0 None	0	0	0.00	0	0	Comments
9				0 None	0	0	0.00	0	0	Comments
10				0 None	0	0	0.00	0	0	Comments
11				0 None	0	0	0.00	0	0	Comments
12				0 None	0	0	0.00	0	0	Comments
13				0 None	0	0	0.00	0	0	Comments
14				0 None	0	0	0.00	0	0	Comments
15				0 None	0	0	0.00	0	0	Comments
16				0 None	0	0	0.00	0	0	Comments
17				0 None	0	0	0.00	0	0	Comments
18				0 None	0	0	0.00	0	0	Comments
19				0 None	0	0	0.00	0	0	Comments
20				0 None	0	0	0.00	0	0	Comments
21	TOTALS				**1,901,355,817**	**149,330,034**	**7.85**	**0**	**0**	

CFC FORM 7

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2018

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
20	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2018

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.			$0
2.			$0
3.		TOTAL	**$0**

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	PRINCIPAL (b)	TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	59,057,848	2,155,255	3,867,526	6,022,781	
2	NCSC	0	0	0	0	
3	Farmer Mac	4,928,777	236,254	493,539	729,793	
4	CoBank	29,474,071	1,288,754	2,859,235	4,147,989	
5		0	0	0	0	
6		0	0	0	0	
7		0	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10	Principal Payments Received from Ultimate Recipients of IRP Loans			0		
11	Principal Payments Received from Ultimate Recipients of REDL Loans			0		
12	**TOTAL (Sum of 1 thru 9)**	**$93,460,696**	**$3,680,263**	**$7,220,300**	**$10,900,563**	

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
	BORROWER NAME	Dakota Electric
	BORROWER DESIGNATION	MN065
	ENDING DATE	12/31/2018

PART R. POWER REQUIREMENTS DATABASE

CLASSIFICATION	CONSUMER, SALES, AND REVENUE DATA	JANUARY CONSUMERS (a)	DECEMBER CONSUMERS (b)	AVERAGE CONSUMERS (c)	TOTAL KWH SALES AND REVENUE (d)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	98,811	99,870	99,341	
	b. KWH Sold				927,054,194
	c. Revenue				119,397,405
2. Residential Sales - Seasonal	a. No. Consumers Served	0	0	0	
	b. KWH Sold				
	c. Revenue				
3. Irrigation Sales	a. No. Consumers Served	390	392	391	
	b. KWH Sold				8,887,461
	c. Revenue				1,049,852
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	4,458	4,520	4,489	
	b. KWH Sold				43,901,164
	c. Revenue				5,718,527
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	2,954	2,961	2,958	
	b. KWH Sold				860,725,459
	c. Revenue				73,608,919
6. Public Street & Highway Lighting	a. No. Consumers Served	164	165	165	
	b. KWH Sold				11,133,836
	c. Revenue				2,043,558
7. Other Sales to Public Authority	a. No. Consumers Served	66	66	66	
	b. KWH Sold				0
	c. Revenue				3,960
8. Sales for Resales-RUS Borrowers	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		**106,843**	**107,974**	**107,410**	
11. TOTAL KWH Sold (lines 1b thru 9b)					**1,851,702,114**
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					**201,822,221**
13. Transmission Revenue					0
14. Other Electric Revenue					1,316,454
15. KWH - Own Use					2,119,811
16. TOTAL KWH Purchased					1,901,355,817
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					149,330,034
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)					412,520

○ None ○ Non-coincident ● Coincident

CFC FORM 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT		
BORROWER NAME		Dakota Electric
BORROWER DESIGNATION		MN065
ENDING DATE		12/31/2018

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	0	0	0	0	0
2.	Residential Sales - Seasonal	0	0	0	0	0	0
3.	Irrigation Sales	0	0	0	0	0	0
4.	Comm. and Ind. 1000 KVA or Less	0	0	0	0	0	0
5.	Comm. and Ind. Over 1000 KVA	0	0	0	0	0	0
6.	Public Street and Highway Lighting	0	0	0	0	0	0
7.	Other Sales to Public Authorities	0	0	0	0	0	0
8.	Sales for Resales - RUS Borrowers	0	0	0	0	0	0
9.	Sales for Resales - Other	0	0	0	0	0	0
10.	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2018

(All investments refer to your most recent CFC Loan Agreement)

7a - PART 1 - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2.	**INVESTMENTS IN ASSOCIATED ORGANIZATIONS**			
5	Capital Term Certificates and Member Capital Securities	0	3,968,042	
6	Patronage Capital GRE	0	110,753,452	
7	Patronage Capital - NRUCFC	0	4,260,228	
8	Investment in Subsidiary and Other Investments	6,683,268	0	
	Subtotal (Line 5 thru 8)	**6,683,268**	**118,981,722**	**0**
3.	**INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS**			
9				
10				
11				
12				
	Subtotal (Line 9 thru 12)	**0**	**0**	**0**
4.	**OTHER INVESTMENTS**			
13				
14				
15				
16				
	Subtotal (Line 13 thru 16)	**0**	**0**	**0**
5.	**SPECIAL FUNDS**			
17				
18				
19				
20				
	Subtotal (Line 17 thru 20)	**0**	**0**	**0**
6.	**CASH - GENERAL**			
21	Anchor Bank-Farmington	0	0	
22	Wells Fargo	75,270	250,000	
23	Petty Cash	0	508	
24		0	0	
	Subtotal (Line 21 thru 24)	**75,270**	**250,508**	**0**
7.	**SPECIAL DEPOSITS**			
25				
26				
27				
28				
	Subtotal (Line 25 thru 28)	**0**	**0**	**0**
8.	**TEMPORARY INVESTMENTS**			
29				
30				
31				
32				
	Subtotal (Line 29 thru 32)	**0**	**0**	**0**
9.	**ACCOUNT & NOTES RECEIVABLE - NET**			
33	Accounts Receivable - Non Electric Billing	629,967		
34	Accounts Receivable - Other	220,215		
35				
36				
	Subtotal (Line 33 thru 36)	**850,182**	**0**	**0**
10.	**COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED**			
37				
38				
39				
40				
	Subtotal (Line 37 thru 40)	**0**	**0**	**0**
	Total	**7,608,720**	**119,232,230**	**0**

CFC FORM 7

NATIONAL RURAL UTILITIES	BORROWER NAME	Dakota Electric
COOPERATIVE FINANCE CORPORATION	BORROWER DESIGNATION	MN065
FINANCIAL AND STATISTICAL REPORT	ENDING DATE	12/31/2018

(All investments refer to your most recent CFC Loan Agreement)

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1			0	0	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			**0**	**0**	**0**

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		**7,608,720**
2	LARGER OF (a) OR (b)		**86,575,584**
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	**45,684,651**	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	**86,575,584**	

Docket No. E-111/GR-19-478

Exhibit__(DEA-19)
Proposed Rate Schedules

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

COREY HINTZ. . . . . VICE PRESIDENT FINANCIAL SERVICES / CFO

BETTY JO KIESOW . . . . VICE PRESIDENT ENGINEERING SERVICES

JEFF SCHOENECKER. . . . . VICE PRESIDENT UTILITY SERVICES

MJYKE NELSON. . . . . VICE PRESIDENT INFORMATION SERVICES / CIO

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3
REVISION: 17

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to individually metered apartment units and master-metered multi-tenant residential facilities. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$10.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1379 per kWh
Other	@	$0.1239 per kWh
Plus Applicable Taxes		

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Billing for Master-Metered Multi-Tenant Residential Facilities

The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master meter times the Fixed Charge and include the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3.5
REVISION: 9

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charge		$ 0.0810 per kWh
Demand Charge		
Summer (June-Aug)	@	$15.50 per kW
Other	@	$11.90 per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0939 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	$0.0756 per kWh
On-Peak:	$0.4421 per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

SCHEDULE EV-1
RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.60 per kW
Winter (Dec-Feb)	@	$21.20 per kW
Other	@	$15.67 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements

Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.0521 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 6.0
Farmington, MN 55024	REVISION: 9

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$15.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1375 per kWh
Other	@	$0.1235 per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$12.01
150 Watt High Pressure Sodium (Closed to new)	$14.26
250 Watt High Pressure Sodium (Closed to new)	$18.83
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$13.25
250 Watt Mercury (Closed to new)	$16.74
400 Watt Mercury (Closed to new)	$22.71
100 Watt High Pressure Sodium	$9.61
150 Watt High Pressure Sodium	$11.78
200 Watt High Pressure Sodium	$14.18
250 Watt High Pressure Sodium	$16.35
400 Watt High Pressure Sodium	$21.24

Plus Applicable Taxes

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$17.44
250 Watt Mercury (Closed to new)	$20.93
400 Watt Mercury (Closed to new)	$26.89
100 Watt High Pressure Sodium (Closed to new)	$13.80
150 Watt High Pressure Sodium (Closed to new)	$15.97
250 Watt High Pressure Sodium (Closed to new)	$20.54
400 Watt High Pressure Sodium (Closed to new)	$25.42
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$14.03
50 Watt High Pressure Sodium (Closed to new)	$8.45
100 Watt High Pressure Sodium (Closed to new)	$10.39
150 Watt High Pressure Sodium (Closed to new)	$12.63
250 Watt High Pressure Sodium (Closed to new)	$17.21
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens) $7.75 per month
Plus Applicable Taxes

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: 1

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$5.50
B (81 to 150 watts)	$7.75
C (151 to 250 watts)	$11.16
D (251 to 350 watts)	$15.04
E (351 to 450 watts)	$19.07

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 9.30	$6.36
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 10.85	$6.12
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.60	$6.98
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.70	$8.68
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a “life of fixture” designation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION | SECTION: V
4300 220TH Street West | SHEET: 15
Farmington, MN 55024 | REVISION: 4

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability

This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service

Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges

The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate

$10.50 per month per service location, plus applicable sales tax.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	16.0
Farmington, MN 55024		REVISION:	4

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any non-residential member for general service uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$13.70 per kW
Other (Sept – May)	@	$10.60 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt. In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 46
GENERAL SERVICE
(Continued)

Billing for Multi-Use Facilities
Multi-use facilities are defined as buildings or complexes that include a combination of commercial or institutional load along with some portion of residential domestic consumption. (For combined billing, commercial use does not include consumption in common areas of multi-tenant residential facilities.) Where service and metering are separated between residential and commercial consumption, such electrical service will be billed under the terms of Schedule 31, Schedule 41, and Schedules 46 or 54 as applicable. Where such service is combined, such electrical service will be billed under the terms of Schedules 46 or 54 as applicable.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged a reconnect fee as well as the monthly fixed charge for all 12 months.

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability
This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate
$5.00/Month per Installation
Plus Applicable Taxes

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.1030 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0813 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service

If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0487 per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric’s conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association’s total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0204 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member’s other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0631 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0352 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.21263 per kWh
Other – Peak Period	@	$0.19863 per kWh
Off-Peak Period	@	$0.09450 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$26.14 per kW
Winter (Dec-Feb)	@	$19.91 per kW
Other	@	$13.67 per kW
		Plus
Maximum Demand Charge	@	$ 5.25 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2890 per kWh
Winter – (Dec-Feb)	@	$0.2320 per kWh
Spring/Fall	@	$0.1880 per kWh
Intermediate Period	@	$0.1060 per kWh
Off-Peak Period	@	$0.0820 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$4.02	$4.02
Distribution - Primary Service	$3.89	$3.89
Distribution - Substation Service	$0.81	$0.81

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability
Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$26.14 per kW
Winter (Dec-Feb)	@	$19.91 per kW
Other	@	$13.67 per kW
Non-Coincidental Demand	@	$ 5.25 per kW
Energy Charge	@	$0.0521 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period
The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand
The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand
The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control
The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance
Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

Minimum Billing Demand

The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment

The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		\$130.00 per month
Communication Fee (meters w/ digital cellular)		\$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	\$26.14 per kW
Winter (Dec – Feb)	@	\$19.91 per kW
Other	@	\$13.67 per kW
Non-Coincidental Demand	@	\$ 5.25 per kW
Energy Charge	@	\$0.0521 per kWh
Excess Demand Charge	@	\$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.

  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge

The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand

The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment

The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August (prorated based on the number of qualifying calendar days in the billing month). In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase $95.00
   Three Phase $110.00

2. Bad Check $11.50

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours $55.00
      2) Outside normal working hours....................$145.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours $185.00
      2) Outside normal working hours....................$340.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck....................$340.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours....................$80.00
      2) Outside normal working hours....................$160.00

6. Pulse Meter (materials and installation) $750.00

7. Transfer/Connection Charge $17.50

8. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way corridor to be cleared is 30 feet with no less than 10 feet of clearance to any open or bare wire.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a flat fee of $1,000.00 plus $11.00 per foot of line extension. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation. In no event will the member be charged more than the actual costs for the extension.
2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.
3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.
4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative’s equipment.
5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.
6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.
7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment Facilities, and Seasonal Accounts

1. Dakota Electric Association will provide single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and multi-tenant residential facilities in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the primary service to a point of connection designated as either a single-phase or three-phase transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows for service provided under the applicable rate schedule:

	Sched. 31 Factor	Sched. 41 Factor	Sched. 46 Factors	Sched. 70/71 Factors
Estimated Extension Costs				
- Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	NA	$10.09	$10.61
- Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	NA	$0.15958	$0.03157	$.02529
- Credit per Residential Unit times number of residential units in the complex	$1,282	NA	NA	NA
= Required Contribution in Aid of Construction				

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

Docket No. E-111/GR-19-478

Exhibit__(DEA-18)
Blackline Mark-up of
Present Rate Schedules

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: II
SHEET: 2
REVISION: 5~~4~~

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

~~LOU ANN WEFLEN~~COREY HINTZ. . . . . VICE PRESIDENT FINANCIAL~~ & INFORMATION~~ SERVICES / CFO

~~RANDY POULSON~~BETTY JO KIESOW . . . . VICE PRESIDENT ENGINEERING SERVICES

~~DIRK ROTTY~~JEFF SCHOENECKER. . . . . VICE PRESIDENT UTILITY SERVICES

MJYKE NELSON…………………….....………. VICE PRESIDENT INFORMATION SERVICES / CIO

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 2
REVISION: 13~~2~~

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3
REVISION: 17~~6~~

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability
Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to individually metered apartment units and master-metered multi-tenant residential facilities. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$10~~9~~.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1379~~08~~ per kWh
Other	@	$0.1239~~168~~ per kWh
Plus Applicable Taxes		

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Billing for Master-Metered Multi-Tenant Residential Facilities
The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master meter times the Fixed Charge and include the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3.5
REVISION: 9~~8~~

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charge		$ 0.081~~76~~0 per kWh
Demand Charge		
Summer (June-Aug)	@	$15.50~~4.70~~ per kW
Other	@	$11.90~~10~~ per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 4.0
REVISION: 2~~1~~

SCHEDULE EV-1
~~PILOT~~ RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

~~Term~~

~~The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.~~

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	~~6.74¢~~$0.0756 per kWh
On-Peak:	~~41.44¢~~$0.4421 per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 4.1
Farmington, MN 55024	REVISION: 2~~1~~

SCHEDULE EV-1
~~PILOT~~ RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge			$30.00 per month
Demand Charge			
Summer (June-Aug)	@		$26.60~~35~~ per kW
Winter (Dec-Feb)	@		$21.20~~0.95~~ per kW
Other	@		$15.67~~50~~ per kW
Energy Charge	@		$0.0521~~499~~ per kWh
Plus Applicable Taxes			

Interruptible

Fixed Charge			$30.00 per month
Demand Charge	@		$4.55 per kW
Energy Charge	@		$0.0521~~499~~ per kWh
Plus Applicable Taxes			

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 5.1
REVISION: 14~~3~~

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements

Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.~~0497~~ 0521 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 6.0
REVISION: 9~~8~~

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$15~~4~~.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1375~~269~~ per kWh
Other	@	$0.1235~~129~~ per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 11.0
REVISION: 18~~7~~

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability
Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$12.01~~0.10~~
150 Watt High Pressure Sodium (Closed to new)	$14.26~~1.99~~
250 Watt High Pressure Sodium (Closed to new)	$18.83~~5.79~~
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$13.25~~0.52~~
250 Watt Mercury (Closed to new)	$16.74~~3.46~~
400 Watt Mercury (Closed to new)	$22.71~~18.54~~
100 Watt High Pressure Sodium	$9.61~~7.56~~
150 Watt High Pressure Sodium	$11.78~~9.46~~
200 Watt High Pressure Sodium	$14.18~~1.41~~
250 Watt High Pressure Sodium	$16.35~~3.25~~
400 Watt High Pressure Sodium	$21.24~~17.67~~
Plus Applicable Taxes	

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 11.2
REVISION: 1<u>5</u>~~4~~

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

<u>Resource and Tax Adjustment (RTA)</u>
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ <u>0939</u> per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

<u>Taxes</u>
The rates set forth are based on taxes as of January 1, 201<u>9</u>~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

<u>Terms of Payment</u>
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$17.44~~5.23~~
250 Watt Mercury (Closed to new)	$20.93~~18.16~~
400 Watt Mercury (Closed to new)	$26.89~~3.25~~
100 Watt High Pressure Sodium (Closed to new)	$13.80~~2.27~~
150 Watt High Pressure Sodium (Closed to new)	$15.97~~4.16~~
250 Watt High Pressure Sodium (Closed to new)	$20.54~~17.95~~
400 Watt High Pressure Sodium (Closed to new)	$25.42~~2.38~~
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$14.03~~1.37~~
50 Watt High Pressure Sodium (Closed to new)	$8.45~~6.70~~
100 Watt High Pressure Sodium (Closed to new)	$10.39~~8.41~~
150 Watt High Pressure Sodium (Closed to new)	$12.63~~0.30~~
250 Watt High Pressure Sodium (Closed to new)	$17.21~~4.09~~
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.0
REVISION: 2~~1~~

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.75~~63~~ per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: ~~Original~~1

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$5.50~~4.81~~
B (81 to 150 watts)	$7.75~~6.71~~
C (151 to 250 watts)	$11.16~~9.66~~
D (251 to 350 watts)	$15.04~~13.05~~
E (351 to 450 watts)	$19.07~~16.52~~

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.3
REVISION: 3~~2~~

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Fixture	Monthly Rate per Fixture Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 9.30~~10.60~~	$6.36~~83~~
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 10.85~~1.24~~	$6.12~~30~~
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.60~~31~~	$6.98~~51~~
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.70~~1~~	$8.68~~7.98~~
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a "life of fixture" designation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220TH Street West
Farmington, MN 55024

SECTION: V
SHEET: 15
REVISION: 4~~3~~

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.50~~00~~ per month per service location, plus applicable sales tax.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 16.0
REVISION: 4~~3~~

SCHEDULE 46
GENERAL SERVICE

Availability
Available to any ~~commercial~~ non-residential member for ~~all~~ general service uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$13.70~~2.26~~ per kW
Other (Sept – May)	@	$ 10.60~~9.16~~ per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of ~~Metered~~ Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt. In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month.

Determination of Energy Charge
The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service
A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 16.1
REVISION: 4~~3~~

SCHEDULE 46
GENERAL SERVICE
(Continued)

Billing for Multi-Use Facilities
Multi-use facilities are defined as buildings or complexes that include a combination of commercial or institutional load along with some portion of residential domestic consumption. (For combined billing, commercial use does not include consumption in common areas of multi-tenant residential facilities.) Where service and metering are separated between residential and commercial consumption, such electrical service will be billed under the terms of Schedule 31, Schedule 41, and Schedules 46 or 54 as applicable. Where such service is combined, such electrical service will be billed under the terms of Schedules 46 or 54 as applicable.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged ~~a disconnect and~~ a reconnect fee as well as the monthly fixed charge for all 12 months.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 18
REVISION: 6~~5~~

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability

This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service

Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges

The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate

$5.00/Month per Installation
Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.103~~094~~0 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.~~0775~~ 0813 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 19.1
REVISION: 4~~3~~

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service

If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION:	V
4300 220th Street West	SHEET:	21
Farmington, MN 55024	REVISION:	17~~6~~

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability

Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0487~~40~~ per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.~~0200~~ 0204 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand

The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes

The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 22
REVISION: 17~~6~~

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability

Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0631~~550~~ per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters

Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.~~0305~~ 0352 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand

The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes

The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION:	V
4300 220th Street West	SHEET:	23.0
Farmington, Minnesota 55024	REVISION:	11~~0~~

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.21263~~1880~~ per kWh
Other – Peak Period	@	$0.19863~~1740~~ per kWh
Off-Peak Period	@	$0.0945~~40~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	24.0
Farmington, Minnesota 55024		REVISION:	14~~3~~

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec-Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
		Plus
Maximum Demand Charge	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$0.0521~~499~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 24.1
REVISION: 10~~9~~

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	25.0
Farmington, Minnesota 55024		REVISION:	~~Orig~~ 1

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2890~~710~~ per kWh
Winter – (Dec-Feb)	@	$0.2320~~210~~ per kWh
Spring/Fall	@	$0.1880~~750~~ per kWh
Intermediate Period	@	$0.1060~~0970~~ per kWh
Off-Peak Period	@	$0.0820~~760~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 31.1
Farmington, Minnesota 55024	REVISION: 6~~5~~

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$4.02~~3.51~~	$4.02~~3.51~~
Distribution - Primary Service	$3.89~~28~~	$3.89~~28~~
Distribution - Substation Service	$0.81~~90~~	$0.81~~90~~

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 41.0
REVISION: 7~~6~~

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130~~10~~.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec-Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
Non-Coincidental Demand	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$ 0.0521~~499~~ per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.~~0497~~ 0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATON
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 42.0
REVISION: 7~~6~~

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130~~10~~.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec – Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
Non-Coincidental Demand	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$ 0.0521~~499~~ per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period ~~shall be~~ shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.

  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge

The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand

The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment

The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.~~0497~~ 0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August (prorated based on the number of qualifying calendar days in the billing month). In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase .... $~~85~~95.00
   Three Phase .... $~~100~~110.00

2. Bad Check .... $~~15.00~~11.50

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours .... $~~50~~55.00
      2) Outside normal working hours .... $~~130~~145.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours .... $~~175~~185.00
      2) Outside normal working hours .... $~~315~~340.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck .... $~~280~~340.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours .... $~~70~~80.00
      2) Outside normal working hours .... $~~140~~160.00

6. Pulse Meter (materials and installation) .... $~~500~~750.00

~~7. Temporary Service~~
   ~~a. Non-Winter Months .... $205.00~~
   ~~b. Winter Months (Oct 15 – Apr 15) .... $340.00~~

7~~8~~. Transfer/Connection Charge $17.50

8~~9~~. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way ~~is~~ corridor to be cleared ~~10 feet on each side of the power line~~is 30 feet with no less than10 feet of clearance to any open or bare wire.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a ~~minimum of $500.00 for an extension of 75 feet or less. For extensions longer than 75 feet, the member will be charged~~flat fee of $~~500~~1,000.00 plus $~~8.30~~11.00 per foot ~~for each foot that the~~of line extension~~ exceeds 75 feet~~. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation. In no event will the member be charged more than the actual costs for the extension.
2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.
3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.
4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative's equipment.
5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.
6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.
7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment ~~Complexes~~Facilities, and Seasonal Accounts

1. Dakota Electric Association will provide ~~overhead or underground,~~ single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and ~~apartment complexes~~multi-tenant residential facilities in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the ~~underground~~ primary service to a point of connection designated as either a single-phase or three-phase ~~padmounted~~ transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows for service provided under the applicable rate schedule:

		Sched. 31 Factor	Sched. 41 Factor~~s~~	Sched. 46 Factors	Sched. 70/71 Factors
	Estimated Extension Costs				
-	Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	NA	~~$6.25~~ $10.09	~~$5.54~~ $10.61
-	Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	NA	~~$0.14779~~ $0.15958	~~$0.01959~~ $0.03157	~~$0.01326~~ $.02529
-	Credit per Residential Unit times number of residential units in the complex	$1,282	NA	NA	NA
=	Required Contribution in Aid of Construction				

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

Docket No. E-111/GR-19-478

Exhibit__(DEA-17)
Present Rate Schedules

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

TABLE OF CONTENTS

CONTACT LIST

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

LOU ANN WEFLEN. . . . . VICE PRESIDENT FINANCIAL & INFORMATION SERVICES

RANDY POULSON . . . . VICE PRESIDENT ENGINEERING

DIRK ROTTY. . . . . .VICE PRESIDENT UTILITY SERVICES

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

INDEX OF SERVICE AREAS

INDEX OF SERVICE AREAS

(All areas are in Dakota County unless otherwise indicated.)

Incorporated Areas

- Apple Valley
- Burnside – Goodhue County
- Burnsville
- Cannon Falls
- Coates
- Eagan
- Farmington
- Hastings
- Inver Grove Heights
- Lakeville
- Miesville
- New Trier
- Rosemount
- Vermillion

Unincorporated Areas

- Cannon Falls - Township - Goodhue County
- Castle Rock Township
- Credit River Township - Scott County
- Douglas Township
- Empire Township
- Eureka Township
- Greenvale Township
- Hampton Township
- Marshan Township
- New Market Township - Scott County
- Nininger Township
- Randolph Township
- Ravenna Township
- Sciota Township
- Stanton Township - Rice County
- Vermillion Township
- Waterford Township
- Webster Township - Rice County
- Welch Township - Goodhue County

DEFINITIONS

TERMS AND ABBREVIATIONS

Association	Dakota Electric Association
Billing Period	Time between two successive electric bills -- as near as practicable to 30 days
Commission	Minnesota Public Utilities Commission
Cooperative	Dakota Electric Association
Member-Owner, Consumer, Consumer/Member Member-Owner/Consumer, Customer	Any person, firm, or corporation receiving electric service from Dakota Electric Association
Seasonal	Designated consumer/member who receives electric service part-time or only during certain months of the year
Year round	On a regular, daily basis, all months of the year

Other terms used are standard throughout the electric industry.

RATE SCHEDULES

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 3
Farmington, MN 55024	REVISION: 16

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability
Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	$14.70 per kW
Other	@	$11.10 per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 4.1
REVISION: 1

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 36
IRRIGATION SERVICE

Availability
Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements
Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.0497 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 6.0
Farmington, MN 55024	REVISION: 8

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

VOLUNTEER FIRE DEPARTMENT RIDER FOR
SCHEDULE 41
SMALL GENERAL SERVICE

Availability

Available to a volunteer fire department located in a municipality that does not have a municipal water system and is required to operate a water pump for fire fighting purposes.

Rider

The three consecutive month demand-threshold of 15 kW will be waived for service to qualifying water pumps that meet the above availability clause and all of the following terms and conditions. Qualifying members will be required to pay all applicable monthly fixed charges, energy charges, and taxes according to the terms of Schedule 41.

Terms and Conditions

1. A qualifying volunteer fire department must use a single motor of 50 horsepower or less to operate the single qualifying water pump.
2. Service to any qualifying water pump must be used for the exclusive purpose of responding to fire emergency incidents and training of volunteer firefighters.
3. If the water pump is used for purposes other than responding to fire emergency incidents and training of volunteer firefighters and the monthly demand exceed 15 kW, then the customer will be subject to transfer to the General Service Rate Schedule 46, which includes a demand charge.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability
Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$10.10
150 Watt High Pressure Sodium (Closed to new)	$11.99
250 Watt High Pressure Sodium (Closed to new)	$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67

Plus Applicable Taxes

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability
Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service
The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.63 per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: Original

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 10.60	$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 11.24	$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.31	$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.71	$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a "life of fixture" designation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION | SECTION: V
4300 220TH Street West | SHEET: 15
Farmington, MN 55024 | REVISION: 3

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

DAKOTA ELECTRIC ASSOCIATION — SECTION: V
4300 220th Street West — SHEET: 16.0
Farmington, MN 55024 — REVISION:: 3

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 46
GENERAL SERVICE
(Continued)

Optional Communication Fee
A monthly Communication Fee of $8.70 will be applied to accounts that participate in riders that require the collection and storage of energy and demand consumption data that is transmitted to the Association by means of digital cellular modem communication.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged a disconnect and a reconnect fee as well as the monthly fixed charge for all 12 months.

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability
This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate
$5.00/Month per Installation
Plus Applicable Taxes

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	\$0.0940 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by \$0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, \$0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service
If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate
Energy Charge	@	\$0.0440 per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by \$0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than \$0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over \$10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or \$1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0550 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
		Plus
Maximum Demand Charge	@	$ 4.75 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Optional Communication Fee

A monthly Communication Fee of $8.70 will be applied to accounts that participate in riders that require the collection and storage of energy and demand consumption data that is transmitted to the Association by means of digital cellular modem communication.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	25.0
Farmington, Minnesota 55024		REVISION:	Orig

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 60
RIDER FOR STANDBY SERVICE

Application

The Rider for Standby Service is applicable to any member who uses a distributed generation system that serves all or a portion of the member's electric energy requirements and where the member chooses to use the Cooperative's electric system to serve that load when the distributed generation system is either partly or wholly unavailable. When the member uses electric service from the Cooperative, such service will be provided under one of the Cooperative's firm retail electric rate schedules to which this Rider is attached.

The member must enter into a contract with Cooperative for the interconnection and operation of an on-site distributed generation system. The distributed generation system at the member site shall not operate in parallel with the Cooperative's system until the installation has been inspected by an authorized Cooperative representative and final written approval is received from the Cooperative to commence parallel operation.

The minimum term of service taken under this Rider shall be one (1) year or such longer period as may be required under an Electric Service Agreement. Following this initial minimum term, a member receiving standby service may terminate standby service and establish service under a firm service tariff schedule within the same time frame as would be required of a new member with a similar firm service load.

Exceptions to this Application include:

A. Any member taking service under Cooperative's Rider for Parallel Generation as established under Minnesota Rules 7835 shall not be required to take service under this Rider for standby services required to temporarily back up distributed generation systems rated at less than 40 kW;
B. Any member taking service under Cooperative's Rider for Distributed Generation Service shall not be required to pay for service under this Rider for standby services required to temporarily back up distributed generation systems rated at 60 kW or less. For any member with distributed generation systems rated at 60 kW or less, standby service will be available to members through their base rates;
C. Any member, in lieu of service under this Rider, may provide physical assurance to ensure that standby service is not taken. A member requesting physical assurance shall agree to furnish and install an approved load limiting device which shall be set and sealed by Cooperative so that member's use of service will not exceed member's contracted demand. The installed cost of the load limiting device shall be paid by member.
D. Any member using on-site distributed generation to participate in Interruptible Service (Schedules 70 and 71) and generation installed for emergency backup during utility outages.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

If a firm standby member has usage in a billing month, then the demand of such usage will be charged at the demand rate as contained in the base tariff to which this Rider is attached. If the usage demand exceeds the Contracted Standby Demand level, the member's Contracted Standby Demand will be adjusted upward as specified in the Billing Demand clause of this Rider. If the member registers electrical usage that coincides with the Cooperative's wholesale power supplier's applicable billing peak, then additional demand charges may be applied by Cooperative to ensure that the member fully compensates Cooperative for such wholesale power costs.

If there is usage by a non-firm standby member, then the demand of such usage will be charged at no less than the demand rate as contained in the base tariff to which this Rider is attached. (Any higher demand charges for non-firm demand use will reflect higher wholesale demand costs incurred to provide such service.) If the usage demand exceeds the Contracted Standby Demand level, the member's Contracted Standby Demand will be adjusted upward as specified in the Billing Demand clause of this Rider. If the member registers electric use that coincides with the Cooperative's wholesale power supplier's applicable billing peak, then additional demand charges may be applied by Cooperative to ensure that the member fully compensates Cooperative for such wholesale power costs. If additional costs are incurred to provide wholesale power during any time of usage by a non-firm standby member, then the non-firm standby member will be responsible for all such costs.

Energy Charge
Energy consumed by a standby member under this Rider will be charged at the same energy rate contained in the base tariff to which this Rider is attached.

<u>Wheeling Fee</u>
Members requiring delivery of energy over the Cooperative's distribution system to a third party will be charged each month, when such distribution wheeling service is available and provided, at a rate equal to the applicable distribution standby reservation fee specified in this rider. If firm wheeling service is required, then arrangements will be made to ensure that distribution system facilities are adequate to provide such firm wheeling service. The cost of any required system modifications will be the responsibility of the entity requesting the firm wheeling service.

Rate Adjustments
Bills shall be subject to all adjustments applicable to consumption under the base schedule to which this Rider is attached.

Billing Demand
The member shall contract for a specific kilowatt demand of standby service with the maximum being the amount of load served by the member's distributed generation system. In the event the Contracted Standby Demand is exceeded in any month, such higher demand shall be considered the new Contracted Standby Demand. Such adjustment of the Contracted Standby Demand applicable to Reservation Fees will recognize circumstances where on-going utility firm service is being provided in addition to standby service.

The billing demand for applying Distribution Reservation Fees for standby service to on-site distributed generation will be determined by subtracting the billing demand for usage supplied by the Cooperative during the same time period as the highest total member electrical demand in the billing month (supplied by the Cooperative and the member's distributed generation system). The billing demand for applying Distribution Reservation Fees for standby service to wholesale generation will be determined by subtracting the billing demand for usage supplied by the Cooperative from the Contracted Standby Demand. The billing demand for applying Generation and Transmission Reservation Fees will be determined according to the terms and conditions of the Cooperative's wholesale power supplier.

The billing demand(s) for usage will be determined and applied as specified in the base tariff to which this rider is attached.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Stranded Investment

Any member who installs load limiting equipment to ensure that standby service is not taken (physical assurance) and does not intend to deliver power into the distribution system will have the option of making a lump sum payment to Cooperative for stranded distribution investment. Dakota Electric shall provide support for the one-time charge to recover stranded distribution investments to physical assurance members before it begins collecting the charge. If such lump sum payment is not made, then the member will be subject to distribution standby charges based on the member's typical demands incurred prior to requesting physical assurance status.

Billing and Terms of Payment

Billing and terms of payment shall be governed as set forth in the Cooperative's applicable base rate schedule.

Terms and Conditions of Service

1. The member shall execute an Electric Service Agreement with the Cooperative which shall specify:
    a. Standard rate schedule (to which this Rider is attached);
    b. Contracted Standby Demand;
    c. Generator Nameplate Rating; and
    d. Type of Standby Service (firm or non-firm).
2. Service hereunder is subject to Cooperative's *Interconnection Process for Distributed Generation Systems* and *Distributed Generation Interconnection Requirements* as may be modified from time-to-time. Current documents are available on DEA's Web site at dakotaelectric.com.
3. Cooperative will install all metering equipment necessary to monitor services provided to ensure adequate measurements are obtained to support necessary application of charges. The member will be charged an up-front lump sum for the installed cost of such metering equipment.
4. The member shall make provision for on-site metering. All energy received from and delivered to the Cooperative shall be separately metered. The Cooperative may require metering of the generation output.
5. The member shall pay for all interconnection costs incurred by the Cooperative made necessary by the installation of the distributed generation system.
6. The Cooperative reserves the right to disconnect the member's generator from the distribution system if it interferes with the operation of the Cooperative's equipment or with the equipment of other Cooperative members.
7. The Cooperative shall not be obligated to supply standby service for a member's load in excess of the capacity for which the member has contracted.
8. The member shall be liable for all damages or costs caused by member's use of power in excess of contracted for capacity.
9. Cooperative may require the member to furnish and install an approved load limiting device which shall be set and sealed by Cooperative so that the member's use of service will not exceed the number of kilowatts contracted for by member.
10. The member shall furnish updated documentation to the Cooperative if there are changes to the maximum capacity and reliability of the power source for which the member requires Standby Service.
11. Cooperative and the member will coordinate the planning and determining of a schedule for performance of periodic maintenance of the member's facilities, such maintenance shall be scheduled to avoid wholesale power billing peaks or as agreed upon in the contract. Cooperative will require the member to provide reasonable notice of its proposed schedule for maintenance. The duration of the agreed maintenance schedule may thereafter be extended only with the consent of the Cooperative in response to the member's request received prior to the end of the maintenance period.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

12. The Cooperative reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Electric Service Agreement.
13. Cooperative may be reimbursed by the member for costs which are incurred, or which have been previously incurred, in providing facilities which are used principally or exclusively in supplying service for any portion of the member's requirements which are to be normally supplied from a source of power other than the Cooperative's electric system.
14. All electricity delivered shall be for the exclusive use of the member and shall not be resold.
15. Member shall indemnify Cooperative against all liability which may result from any and all claims for damages to property and injury or death to persons which may arise out of or be caused by the erection, maintenance, presence, or operation of the co-generation facility or by any related act or omission of the member, its employees, agents, contractors or subcontractors.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION

Application
The Rider for Distributed Generation is applicable as follows to any member taking service under one of the Cooperative's standard electric rate schedules and who has entered into an Electric Service Agreement with Cooperative for the interconnection and operation of an on-site extended parallel distributed generation system:

1. The distributed generation system must be an operable, permanently installed or mobile generation facility connected in parallel to the utility distribution system serving the member receiving retail electric service at the same site.
2. The distributed generation system must be fueled by either natural gas, a renewable fuel, or another similarly clean fuel or combination of fuels.
3. The distributed generation system can not have more than 10 MW of interconnected capacity at a point of common coupling to Cooperative's distribution system.
4. The interconnection and operation of the distributed generation system at each point of common coupling shall be considered as a separate application of the Rider.
5. All provisions of the applicable standard service schedule shall apply to distributed generation service under this Rider except as noted below.

In lieu of service under this Rider, the member and Cooperative may pursue reasonable transactions outside the Rider; or member may take service, as applicable, under Cooperative's Rider for Parallel Generation as established under Minnesota Rules 7835 – Cogeneration and Small Power Production.

Definitions
Member is an entity receiving retail electric service from Cooperative at the same site as the distributed generation system.

Extended Parallel means the distributed generation system is designed to remain connected with the Cooperative's distribution system for an extended period of time.

Scheduled Maintenance service is energy, or energy and capacity, supplied by the Cooperative during scheduled maintenance of the member's non-utility source of electric energy supply (distributed generation system).

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Supplemental service is electric energy, or energy and capacity, supplied by the Cooperative to the member when the member's non-utility source of electricity (distributed generation system) is insufficient to meet the member's own load. Supplemental Service can take two forms: residual retail service and load-following service. **Residual Retail Service** is intended for a Dakota Electric member who has an alternate source of electric energy supply which normally supplies only a portion of the member's electrical load requirements and who requires firm service for the remaining portion of the member's electrical requirements. Such Residual Retail Service is available under the Cooperative's firm retail electric rate schedule to which this rider is attached. **Load Following Service** is intended for a Dakota Electric retail member who has an alternate source of electric energy supply which has an output that is variable and dependent on the thermal load characteristics of the retail member and therefore, serves all or a portion of the member's electrical load requirements for a portion of the time and requires use of utility service for supply of energy at all other times. This load following service will be evaluated and contracted for on an individual basis with a member based on the specific variable load requirements of the member. Since a member may have control over the thermal load characteristics that affect the output of distributed generation facilities in this situation, we believe the best way of providing service is on an individual contracted basis. This will recognize that some members may rely on utility service during high cost on-peak periods while other members may require such utility service only during lower cost off-peak periods.

Unscheduled Outage service is energy, or energy and capacity, supplied by the Cooperative during unscheduled outages of the member's non-utility source of electric energy supply (distributed generation system).

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Services
Services provided under this Rider may include services from the Cooperative to member and from member to Cooperative. The following rates, charges, credits and payments are applicable for such services in addition to all applicable charges for service being taken under Cooperative's standard rate schedule:

Services from Cooperative to Member
A monthly service charge to recover incremental metering, operation, and maintenance costs may be applied upon Commission approval.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Services from Cooperative to Member

Interconnection Services
Interconnection services include services such as engineering/design studies, Cooperative system upgrades and testing as further described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems*. Charges for such interconnection services shall be as described in the Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Supply Services
Supply services include standby services such as scheduled maintenance and unscheduled outages as provided under Cooperative's *Rider for Standby Service*. Supplemental service is available under the Cooperative's firm retail electric rate schedule to which this Rider is attached.

Transmission Services
Transmission services include reservation and delivery of capacity and energy on either a firm or non-firm basis and those ancillary services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation over Transmission Providers' Transmission System. These ancillary services include services such as Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control from Generation Sources, Regulation and Frequency Response, Generator Imbalance, Operating Reserve – Spinning Reserve and Operating Reserve – Supplemental Reserve. Transmission Services are provided as applicable under Cooperative's wholesale power supplier's approved Open Access Transmission Tariff (OATT).

Distribution Services
Distribution services include reservation and delivery of capacity and energy and those indirect services that are necessary to support the delivery of capacity and energy over Cooperative's distribution system. These indirect services include allocated support services or expenses such as operation and maintenance, member accounts, member service and information, administrative and general, depreciation, interest and taxes. Members requiring contracted distribution standby service of more than 60 kW and/or delivery of energy and capacity over Cooperative's distribution system to a third party will be charged for such distribution services at a rate equal to the distribution charge specified in the Cooperative's *Rider for Standby and Supplemental Service*.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Services from Member to Cooperative

Capacity/Energy

Member may sell all of the energy produced by the distributed generation system to the Cooperative, use all the distributed generation energy to meet its own electrical requirements, or use a portion of the energy from the distributed generation system to meet its own electrical needs and sell the remaining energy to the Cooperative.

If the member offers to sell energy to the Cooperative, then such energy and capacity shall be purchased by the Cooperative's wholesale power supplier under the rates, terms and conditions for such purchases as established by the wholesale power supplier. Great River Energy Rate Rider T is available on GRE's Web site; greatriverenergy.com, and on DEA's Web site; dakotaelectric.com.

Distribution Credits

A distribution credit may be given if the distributed generation system allows the Cooperative to defer or avoid distribution system upgrades. Distribution credits to the member should equal the Cooperative's avoided distribution costs resulting from the installation and operation of the distributed generation system. The Cooperative shall provide, upon member's written request, areas of the distribution system that could be likely candidates for distribution credits as determined through the Cooperative's normal planning process. The Cooperative shall also provide to the member the minimum size distributed generation system required in each of the areas to qualify for the distribution credit along with general operational requirements necessary for the distributed generation system to meet, so as to be able to receive distribution credits.

Upon receiving an interconnection application from the member for a distributed generation interconnection, along with a written request for distribution credits, the Cooperative will complete an initial screening study to determine if the project has the potential to receive distribution credits. The member shall be responsible for the cost of the screening study. If the Cooperative's study shows that there exists potential for distribution credit, the Cooperative shall, at its own expense, pursue further study to determine the distribution credit, as part of its annual distribution planning study. If distribution credits are identified, then such credits will be paid in conjunction with an agreement with the member to supply distribution support utilizing the member's generation system.

Line Loss Credits

If the member requests the Cooperative to provide a specific line loss study, at the member's expense regardless of the study's outcome, the member may be eligible for additional line loss credits if the study supports such credits.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Renewable Credits

If the member installs a renewable distributed generation system and the Cooperative's wholesale power supplier's purchase of energy and capacity from such facility allows the wholesale power supplier to avoid the need to purchase renewable energy elsewhere, then the purchase of such renewable energy and capacity will equal the avoided cost of renewable purchases as provided under the wholesale power supplier's applicable rates, terms and conditions for such purchases In the event that the member producing the power receives renewable energy credits – that is, the member is paid by the purchasing company the avoided cost of renewable energy purchases – then this transaction will constitute a transfer from the member to the purchasing company of the property rights for those renewable attributes specific to the renewable energy generated by the member and for which the purchasing company paid renewable energy credits. The member may receive renewable credits or tradable emission credits but not both.

Tradable Emissions Credits

If the purchase of energy and capacity by the Cooperative's wholesale power supplier under the "must buy" provision described above results in the wholesale power supplier receiving an economic value associated with tradable emissions, then tradable emissions credits will be provided to the member under terms established by the wholesale power supplier that equal the credit revenues associated with the DG facilities of such emission credits received by the wholesale power supplier. The member may receive either renewable credits or tradable emissions credits but not both.

Terms and Conditions of Service

The following terms and conditions apply to this Rider:

1. Service hereunder is subject to Cooperative's *Interconnection Process for Distributed Generation Systems* and *Distributed Generation Interconnection Requirements* as may be modified from time-to-time. Current documents are available on DEA's Web site: dakotaelectric.com.

2. Cooperative will install all metering equipment necessary to monitor services provided to ensure adequate measurements are obtained to support necessary application of rates, charges, credits and payments. The member will be charged an up-front lump sum for the installed cost of such metering equipment.

3. The member will be compensated monthly for all energy delivered to Cooperative's wholesale power supplier. The timing for these payments is subject to annual review.

4. The member shall make provision for on-site metering. All energy received from and delivered to the Cooperative shall be separately metered. The Cooperative may require metering of the generation output.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

5. The member shall pay for all interconnection costs incurred by the Cooperative made necessary by the installation of the distributed generation system.

6. Power and energy purchased by the member from the Cooperative shall be under the applicable retail rates for the purchase of electricity.

7. The Cooperative reserves the right to disconnect the member’s generator from its system if it interferes with the operation of the Cooperative’s equipment or with the equipment of other Cooperative members.

8. The member shall execute an Electric Service Agreement with the Cooperative which may include, among other provisions, a minimum term of service.

Billing and Terms of Payment

Billing and terms of payment shall be governed as set forth in the Cooperative’s applicable base rate schedule.

To the extent that Cooperative receives service from a member under this Rider, payment for such services shall be netted against any charges for Cooperative-supplied services hereunder.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 41.0
Farmington, MN 55024	REVISION: 6

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability
Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period
The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand
The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand
The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control
The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance
Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

<u>Minimum Billing Demand</u>
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

<u>Power Factor Adjustment</u>
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

<u>Primary Voltage Service</u>
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

<u>Resource and Tax Adjustment (RTA)</u>
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0497 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

<u>Taxes</u>
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

<u>Terms of Payment</u>
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATON	SECTION: V
4300 220th Street West	SHEET: 42.0
Farmington, MN 55024	REVISION: 6

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge
The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0497 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 90
OPTIONAL RENEWABLE ENERGY RIDER
(**Wellspring Wind and Wellspring Solar**)

Availability

Available to any member taking service concurrently under another rate schedule. This rate is for the purchase of energy from wind and solar renewable sources. Members requesting service under this optional rider must remain on the rider for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Subscription Requirement

Members desiring to participate in the Optional Renewable Energy Rider will specify the type of resource and either a fixed or a variable monthly amount of renewable energy (in one or more 100 kWh blocks) that they will purchase. The fixed monthly subscription level may not exceed a member's lowest actual or estimated monthly consumption level. Under the variable monthly subscription, the member will automatically purchase the maximum number of 100 kWh blocks or renewable energy each month that does not exceed the member's actual consumption level for that month.

Monthly Rate

Wind Renewable Energy (per 100 kWh)	$0.20
Solar Renewable Energy (per 100 kWh)	$2.00
Plus Applicable Taxes	

The monthly renewable energy rate will consist of the wholesale power cost for this service plus any over- or under-recovery balance from the prior year. This monthly renewable energy rate will be shown as a separate line item on a member's bill. This charge per 100 kWh is in addition to the applicable rate schedule currently serving the member.

Rate Adjustments

The monthly rate will be adjusted under the following two circumstances. First, the rate will change to reflect changes in wholesale power costs associated with this service. Dakota Electric will file such wholesale rate adjustment calculations with the Minnesota Public Utilities Commission prior to implementing the rate revision. Second, the monthly rate will include any over- or under-recovery of renewable energy costs approved for recovery under this rider. In early January each year, Dakota Electric will submit a filing to the PUC documenting any change in wholesale power costs and any over- or under-recovery of renewable energy costs for the prior calendar year.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 90
OPTIONAL RENEWABLE ENERGY RIDER
(**Wellspring C&I**)

Availability

Wellspring C&I is available to commercial and industrial member-consumers receiving service under Schedules 46, 54, 70, or 71. Participating members may purchase the retirement of any quantity of Renewable Energy Certificates (RECs) by Dakota Electric's wholesale power supplier, specified in kWh, in relation to either a designated annual percentage of load (%), or monthly energy amount (kWh) up to their total annual energy usage supplied by Dakota Electric. Service is subject to the established rules and regulations of the Association.

Subscription Requirements

A retail agreement between Dakota Electric and the member-consumer is required that reflects a five (5) to ten (10) year commitment and conforms to specifications set forth in the annual program guide of Dakota Electric's wholesale power supplier. C&I member-consumer purchases must meet one of the following minimum thresholds:

a) 1,500,000 kWh annually per participant; or
b) corporate aggregation level at 5,000,000 kWh annually.

Any retail sale to an individual member-consumer or multi-site entity that is expected to exceed 10,000,000 kWh annually, anytime during the term, requires Dakota Electric to receive prior approval from our wholesale power supplier.

To be eligible for Wellspring C&I, retail and wholesale agreements must:

a) be executed prior to September 1st,
b) be for full calendar year terms,
c) commence on either the preceding, or next occurring, January 1st, and
d) have a copy provided to the wholesale power supplier within fifteen (15) days of execution.

Monthly Rate

Wellspring C&I will be billed as a specified rate per kWh for the entire five (5) to ten (10) year term of the agreement between Dakota Electric and the individual member-consumer. The rate per kWh for Wellspring C&I reflects a pass-through of charges from the wholesale power supplier. The rate for each agreement is established at the time the agreement is signed. This monthly renewable energy rate will be shown as a separate line item on a member's bill. This charge is in addition to the applicable charges for the rate schedule currently serving the member.

Termination Penalties

Early termination penalties will apply to agreements that are terminated early for convenience or otherwise voluntary reasons. Early termination penalty shall equal the last 12 months purchase amount multiplied times the purchase rate as specified in the agreement. Early termination penalties may be waived for agreements that are terminated early for involuntary reasons such as facility closings, ownership change, bankruptcy, etc.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase $85.00
   Three Phase $100.00

2. Bad Check $15.00

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours $50.00
      2) Outside normal working hours..$130.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours $175.00
      2) Outside normal working hours..$315.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck..$280.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours…………………………………………………….$70.00
      2) Outside normal working hours………………………………………..$140.00

6. Pulse Meter (materials and installation) $500.00

7. Temporary Service
   a. Non-Winter Months $205.00
   b. Winter Months (Oct 15 – Apr 15) $340.00

8. Transfer/Connection Charge $17.50

9. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

RESOURCE ADJUSTMENT RIDER

Application

Applicable to all bills for retail electric service that include a purchased power cost adjustment clause.

Resource Adjustment (RA)

Monthly member energy charges shall be adjusted for changes in purchased power costs and changes in Dakota Electric's Tracker Account balance. These two changes shall be reflected on member bills through a Resource Adjustment. The applicable RA factor shall be determined annually as described below.

Determination of the Resource Adjustment Factor

The Resource Adjustment factor shall be determined by adding the annualized power cost adjustment factor to the most recent year-ending Tracker Account factor. The Tracker Account factor shall be the quotient of the recoverable Tracker balance, divided by projected retail energy sales that are applied in the power cost adjustment factor

The year used for the annualized Resource Adjustment will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RA shall be filed with the Public Utilities Commission each year before implementation.

All costs appropriately charged to Dakota Electric's Tracker Account shall be eligible for recovery through this adjustment. Revenues received from the application of the RA shall be applied toward power costs and the Tracker Account in a manner consistent with the determination of the RA factor.

ENERGY COST ADJUSTMENT RIDER

Application

Applicable to service provided under Interruptible Service Schedule 70, Schedule 71 and Interruptible Irrigation (Schedule 36).

Determination

The Energy Cost Adjustment (ECA) will increase/decrease by $0.0001 per kilowatt-hour for every corresponding $0.0001 increase/decrease in Dakota Electric's projected wholesale cost per kilowatt-hour sold applicable to Schedule 70, Schedule 71, and Interruptible Irrigation. Total projected energy costs for this service will include all energy costs for energy supply excluding costs for load management programs and including applicable wholesale energy cost adjustments. This adjustment will be calculated annually and applied monthly on member bills.

PROPERTY TAX ADJUSTMENT RIDER

Application
Applicable to all bills for retail electric service under Dakota Electric's retail rate schedules.

Rider
There shall be included on each member's bill a Property Tax Adjustment which shall be the applicable Property Tax Adjustment factor multiplied by the member's energy usage before any applicable city surcharge or sales tax. The Property Tax Adjustment factor shall be reflected on member bills through a "Resource and Tax Adjustment" line item on member bills. The applicable Property Tax Adjustment factor shall be determined annually as described below.

Determination of the Property Tax Adjustment Factor
The Property Tax Adjustment factor shall be determined by first allocating the incremental annual property tax expense to each class according to each class' relative responsibility for property taxes as determined in the most recent general rate case class cost of service study. Each class allocation will then be divided by projected retail energy sales applicable to each class to determine the property tax adjustment factor for each class.

Calendar-year property tax adjustment factors will be recovered during the period from January 1 through December 31. The property tax adjustment factor shall be filed with the Public Utilities Commission each year before implementation.

Recoverable Property Tax Expenses
Recoverable Property Tax expenses shall be the incremental property tax expense not recovered through base rates as estimated for the designated projected twelve month recovery period, plus unrecovered or less over-recovered Recoverable Property Tax expenses for a prior designated twelve month recovery period.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 54.0
REVISION: 10

FRANCHISE FEE SURCHARGE RIDER

Application

A surcharge will be included in the monthly bills computed under the indicated rate schedules effective in the following Minnesota Communities.

The Cooperative remits 100% of the franchise fees collected to the local government.

Rate Schedules		Apple Valley [a] (2.0%)	Burnsville [b]	Inver Grove Heights [c]
Residential and Farm Service	(Schedule 31)	X	$1.00	$2.75
Residential and Farm Demand Control Rate	(Schedule 32)	X	$1.00	$2.75
Residential Electric Vehicle Service	(Schedule 33)	X	NA	NA
Irrigation Service	(Schedule 36)	X	$3.00	$3.00
Small General Service	(Schedule 41)	X	$3.00	$3.00
Security Lighting Service	(Schedule 44)	X	NA	NA
Street Lighting Service	(Schedule 44-1)	X	NA	NA
Street Lighting Service	(Schedule 44-2)	X	NA	NA
Custom Residential Street Lighting	(Schedule 44-3)	X	NA	NA
Low Wattage Unmetered Service	(Schedule 45)	X	NA	NA
General Service <75 kW	(Schedule 46)	X	$10.00	$25.00
General Service ≥75 kW	(Schedule 46)	X	$45.00	$25.00
Municipal Civil Defense Sirens	(Schedule 47)	X	NA	NA
Geothermal Heat Pump	(Schedule 49)	X	NA	NA
Controlled Energy Storage	(Schedule 51)	X	NA	NA
Controlled Interruptible Service	(Schedule 52)	X	NA	NA
Residential and Farm Time-of-Day Service	(Schedule 53)	X	$1.00	$2.75
General Service Optional TOD <75 kW	(Schedule 54)	X	$10.00	$25.00
General Service Optional TOD ≥75 kW	(Schedule 54)	X	$45.00	$25.00
Residential and Farm Time-of-Day Service	(Schedule 56)	X	$1.00	$2.75
Standby Service Rider	(Schedule 60)	X	NA	NA
Distributed Generation Rider	(Schedule 61)	X	NA	NA
Interruptible Service (Full Interruptible)	(Schedule 70)	X	$45.00	$25.00
Interruptible Service (Partial Interruptible)	(Schedule 71)	X	$45.00	$25.00
Cycled Air Conditioning Service	(Schedule 80)	X	NA	NA
Renewable Energy Rider	(Schedule 90)	X	NA	NA

a. The maximum fee that will be applied to any account will not exceed $25.00 per month.
b. Effective July 2016.
c. Effective with the January 2018 billing month.

FRANCHISE FEE SURCHARGE RIDER (Continued)

Notification

The Cooperative will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Cooperative receives less than 60 days' notice of a repealed or reduced fee from a city, the Cooperative will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

When a new franchise fee is implemented, the Cooperative will notify affected consumers through a joint letter mailed on behalf of the Cooperative and local government entity imposing the franchise fee. Such joint letters will be submitted to the Commission along with other relevant documentation referenced above and will at least include the following statement:

> The Cooperative provides electric service within the City limits under the terms of a Franchise Agreement with MUNICIPALITY. An electric Franchise Fee of X% OF GROSS REVENUES/$X PER METER/$ PER KWH will be imposed on consumers effective MM/DD/YYYY. The line item will appear on your bill as "City Fee." The Cooperative remits 100% of this fee to the MUNICIPALITY."

The franchise fee will be labeled as "City Fee" on monthly bills.

COMPETITIVE SERVICE RIDER

Availability

Available at Association's discretion to Commercial and Industrial members that have electric service requirements which are subject to effective competition. Effective competition exists if a member is located in Association's service territory and has the ability to obtain its energy requirements from an energy supplier not rate-regulated by the Minnesota Public Utilities Commission.

Rate

Standard service rate provisions apply except the level of the demand and/or energy charges may be decreased for each member based on a consideration of member's load characteristics and lowest cost competitive energy supply.

Terms and Conditions of Service

1. Members must provide Association with information which documents that member is not likely to take service provided by any other electric tariff available from Association.
2. Minimum load served under this Rider is 500 kW.
3. Member must execute an electric service agreement with Association which will include:
   a. The minimum rate under this Rider, which will recover at least the incremental cost of providing service, including the cost of incremental capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.
   b. The maximum rate reduction possible under this Rider, which will not exceed the difference between the standard tariff and the cost to the member of the lowest cost competitive energy supply.
   c. The term of service under this Rider, which must be no less than one year and no longer than five years.
   d. The size of the load served under this Rider
   e. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for member, an explanation of why an electric energy review was not necessary will be included.

COMPETITIVE SERVICE RIDER
(Continued)

4. The Association within a general rate case is allowed to seek recovery of the difference between the standard tariff and this Rider times the usage level during the test year period.
5. A rate under this Rider shall meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other members in this same member class.
6. Unless the Commission determines that it would be in the public interest, a rate under this Rider shall not compete with district heating and cooling provided by a district utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, paragraph (c).
7. A rate offered under this Rider may not be offered to a member in which the Association has a financial interest greater than 50 percent.

Regulatory Review

This rate offered under this Rider will be effective on an interim basis after filing by Association of the proposed rate with the Commission and upon the date specified in the electric service agreement. If the Commission does not approve the rate, Association may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the member who was offered the competitive rate.

The Commission has the authority to approve, modify or reject a rate under this Rider. If the Commission approves the competitive rate, it becomes effective as agreed to by the Association and member. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Association and the member. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Association on its behalf or on the behalf of the member, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

MEMBER ENERGY EXCHANGE RIDER

Availability

The Member Energy Exchange Program is available to any general service member with 100 kW minimum demand reduction capability taking service concurrently under either rate schedule 46, 70 or 71. This rider provides Dakota Electric and its power supplier(s) with the opportunity to pay members for reducing their energy needs during certain peak periods. Member participation during each individual exchange period is strictly voluntary. Members may elect to participate in an individual exchange period or decline without explanation. This rider is available at the Cooperative's discretion.

Participation Requirements

The following participation requirements apply:

1. Member must provide a minimum electrical demand reduction of 100 kW;
2. Member loads covered by a load management program or rate are not eligible;
3. Member must reduce energy requirements for a minimum of two hours; and
4. Member may be required to reduce energy requirements for a maximum of six hours in any 24-hour period.

Notification and Pricing

Two options are available for customers participating in the Member Energy Exchange Program

Option A – This option is for a member requiring a 24-hour advance notice. Option A notification and pricing is as follows:

1. Member receives a day-ahead posted price;
2. Member indicates intended action plans for the next day;
3. Member receives a two-hour notification prior to the beginning of the energy reduction period;
4. Member curtails energy usage; and
5. Member receives a separate payment or a credit on the electric bill.

MEMBER ENERGY EXCHANGE RIDER
(Continued)

Notification and Pricing (continued)

Option B – This option is for a member that can respond to a maximum two-hour notice. Option B notification and pricing is as follows:

1. Member receives a two-hour notification that includes the posted price prior to the beginning of the energy reduction period (Option B will be valued higher than Option A);
2. Member curtails energy usage; and
3. Member receives a separate payment or a credit on the electric bill.

Validation

The following metering and validation provisions will apply for participation in this program:

1. Member must have electronic 15-minute interval metering, interrogation software and telephone line;
2. An assessment of the verifiable energy reduction capability will be performed before a member may participate; and
3. The member's ability to reduce demand to the agreed-upon level will be tested and verified.

VOLUNTARY ENERGY REDUCTION RIDER

Availability

The Voluntary Energy Reduction Rider is available to any General Service member that is demand metered. This rider provides Dakota Electric and its power supplier(s) with the opportunity to pay members for reducing their energy needs during certain peak periods. Member participation is strictly voluntary. This rider is available at the Cooperative's discretion.

Participation Requirements

The following participation requirements apply:

1. Member must be demand metered by Dakota Electric;
2. Member loads covered by a load management program or rate are not eligible; and
3. Member must reduce energy requirements for a minimum of two hours.

Notification and Pricing

Dakota Electric will contact members and determine their interest in participating in the Voluntary Energy Reduction Program. The offer to participate in this rider will include:

1. An estimate of the member's demand reduction based on historical patterns;
2. Indication of duration of voluntary reduction;
3. Identification of beginning hour and ending hour of voluntary reduction; and
4. Offer price per kWh.

Participating members will curtail specified energy usage during identified voluntary reduction periods. Members will then receive compensation through a separate payment or a credit on the electric bill.

MEMBER SPECIFIC DISCOUNT RIDER

Availability

Available to Commercial and Industrial members receiving service under Schedules 46 and 54 that have electric load that qualifies for a targeted wholesale capacity rate discount from the Association's wholesale power supplier. Service will be provided under the terms of a member-specific contract.

Rate

Standard rate provisions for Schedules 46 and 54 apply, except that a discount will be applied to the monthly bill based on the member's demand during the wholesale coincident billing peak and the qualifying discount level. The monthly billing discount is available for up to five (5) consecutive years measured from the date electric service is first provided to the qualifying new retail load, or under other terms as offered by the Association's wholesale power supplier.

A monthly Communication Fee of $8.70 per meter will be charged for digital cellular modem communication.

Terms and Conditions of Service

1. Available to new retail load with monthly coincident billing peak demand greater than or equal to 750 kW.
2. Monthly non-coincident load factor must be greater than or equal to 40%.
3. Dakota Electric must supply all (100%) of the retail load's electric requirements. On-site generation is not allowed.
4. Load will be ineligible for Interruptible Commercial and Industrial Service (Schedules 70 and 71) during the term of the agreement and, upon expiration, for an additional three years.
5. Each month that the metered coincident billing peak demand of the qualifying load is greater than or equal to 750 kW, a discount will be applied to the demand of the qualifying load as specified by Dakota Electric's wholesale power supplier.
6. No discount will be applied to the demand of the member's load in a month where the metered coincident billing peak demand of the load is less than 750 kW.
7. A Member Specific Rate may not be offered to a member in whom the Association has a financial interest greater than 50 percent.
8. Member must provide Association with information which documents that the member electrical load from the Association will qualify for the targeted wholesale capacity rate discount from Dakota Electric's power supplier.

MEMBER SPECIFIC DISCOUNT RIDER
(Continued)

9. Member must execute an electric service agreement with Association which will at least include:
   a. The billing rate components, specified as credits or charges as applicable.
   b. The term in years for firm service.
   c. The size of the load served under this Rider.
   d. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for member, an explanation of why an electric energy review was not necessary will be included.
10. The Association will track the wholesale power cost credits associated with each Member Specific Discount and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.

Regulatory Review
Each Member Specific Discount will be filed with the Public Utilities Commission (as a confidential information filing) before implementation. These confidential information filings will provide an overview of the discount being provided and confirm that the discount is a pass-through from Dakota Electric's wholesale power supplier.

LARGE LOAD HIGH LOAD FACTOR RIDER

Availability
Available to Commercial and Industrial members receiving service under Schedules 46 and 54 that have electric load at an individual site that meets the qualifying demand and load factor thresholds of the Association's wholesale power supplier.

Rate
Standard service rate provisions for Schedules 46 and 54 apply, except that a discount will be applied to the member's monthly bill based on the member's calculated load factor. Qualifying loads may move between load factor tiers monthly based on a changing ANCLF (or PNCLF). Credits will be issued monthly for the following load factor tiers:

Tier	ANCLF / PNCLF
1	62.00 % to 74.99%
2	75.00% to 89.99%
3	90.00 % to 100.00 %

A monthly Communication Fee of $8.70 per meter will be charged for digital cellular modem communication.

Terms and Conditions of Service

1. Dakota Electric must supply all (100%) of the member's electric requirements. On-site generation is not allowed.
2. The member will not receive a credit under both the LLHLF rate and any other load management program.
3. The member's qualifying load at an individual site must achieve a Non-Coincident Peak Demand (NCPD) of at least 1,000 kW in any period of sixty (60) consecutive minutes at least one time in the preceding 12-month period.
    a. NCPD shall be the highest actual metered demand and not an estimated, average or calculated value.
4. The member's qualifying load at an individual site must have an Annual Non-Coincident Load Factor (ANCLF) in the preceding 12-month period that is greater than or equal to 62%.
    a. All Load Factor calculations will be based only on the individual member's actual demand and energy recorded during the preceding twelve (12) months at an individual site.
    b. No adjustments will be made for any load management programs, abnormal weather, member load anomaly, or member growth (expected or actual).

LARGE LOAD HIGH LOAD FACTOR RIDER
(Continued)

5. New metered loads with less than twelve (12) months of actual load data may substitute a Partial-Year Non-Coincident Load Factor (PNCLF) for the ANCLF qualification requirement, only during the first eleven (11) months of electric service.
    a. If a member has a significant expansion of load at the site and the member's NCPD increases by more than 50% over the previous year's average monthly Peak Demand, then the member shall have the ability to use the PNCLF as the basis for the credit that applies to the entire member load.
    b. Once a member "resets" the load factor calculation and begins using the PNCLF, the member may not revert to the historical ANCLF for the next 11 months.
    c. Transfer of ownership alone does not qualify load to be considered "new".
6. No loads will qualify for the LLHLF credit retroactively. Monthly calculations will be made for qualification in the previous month.
7. Dakota Electric will automatically adjust the LLHLF credit provided to members to pass through any future changes made by its wholesale power supplier.
8. The Association will track the wholesale power costs associated with all Large Load High Load Factor credits and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.

SCHEDULE 72
CONTRACT RATE SERVICE

Availability

Available at Association's discretion, within its assigned service territory, to large Commercial and Industrial members that are subject to effective competition and have electric service requirements as described in the Terms and Conditions of Service clause. Effective competition exists if the member has the ability to obtain its energy requirements from an energy supplier not rate-regulated by the Minnesota Public Utilities Commission (Commission). Service will be provided under the terms of a member-specific electric service agreement.

Rate

Applicable charges will be detailed in an electric service agreement.

Terms and Conditions of Service

1. Individual contract rates will only be offered in coordination with Dakota Electric's wholesale power supplier.
2. Minimum load served under this Contract Service is 10 MW.
3. Distribution and/or transmission facilities to serve the Contract Service load will be provided as specified in the electric service agreement with the member. A contribution in aid of construction (CIAC) will be required if the estimated investment in distribution and/or transmission facilities is not justified by the anticipated revenue.
4. Member must execute an electric service agreement with Association which will at a minimum include:
   a. Location of the consumer site within the Cooperative's service territory.
   b. Affirmation that 1) the consumer is able to locate the load/facility at another site and obtain energy requirements from an energy supplier that is not regulated by the Commission and 2) that the consumer is not likely to take service from the Cooperative if the consumer was charged the Cooperative's standard tariffed rate.
   c. Identification of billing components and rates to be applied to each component.
   d. The term of service under this Contract Service.
   e. The size of the load (in MW) served under this Contract Service.
   f. Identification of any distribution and/or transmission facilities that must be installed to serve the Contract Rate Service load and the responsibility for installation and future maintenance costs.
   g. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for the member, an explanation of why an electric energy review was not necessary will be included.

SCHEDULE 72
CONTRACT RATE SERVICE
(Continued)

1. Each member receiving service under the Contract Rate Service will be responsible for all wholesale power costs associated with their electric service. The Association will track the wholesale power costs associated with all contract rates and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Commission.
2. A rate under this Contract Service will meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other members in this same member class.
3. A rate under this Contract Service will not compete with district heating and cooling provided by a district utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, paragraph (c).
4. A rate offered under this Contract Service will not be offered to a member in whom the Association has a financial interest greater than 50 percent.
5. Contract rates must be approved by the Commission before becoming effective.

Regulatory Review
Dakota Electric must file any proposed contract rates for individual members with the Commission. Such filings will clearly identify all confidential information as trade secret with designations as specified in Minnesota Rules. The Association will at a minimum include the following information in Contract Rate filings:

1. Information required in “Miscellaneous Filings” to the Commission as specified in applicable Minnesota Rules.
2. Information included in the electric service agreement.
3. Identification of wholesale power costs and responsibility of the member for all such costs.
4. Documentation of incremental cost recovery for service to the contract rate consumer and evaluation of impact on other Cooperative members.

The Commission will approve, modify, or reject the contract rate filing under this Contract Rate Service within 90 days. If the Commission approves the contract rate, it becomes effective as agreed to by the Association and member. If the contract rate is modified by the Commission, the Commission shall issue an order modifying the contract rate subject to the approval of the Association and the member. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Association on its behalf or on behalf of the member, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the contract rate, it shall issue an order indicating the reasons for the rejection.

ADVANCED GRID INFRASTRUCTURE RIDER

Application
Applicable to bills for electric service provided under the Association's metered retail rate schedules.

Rider
There shall be included on each member's monthly bill an Advanced Grid Infrastructure (AGi) Rider adjustment. The AGi Adjustment shall be applied on a per-meter basis before any city surcharge and sales tax.

Determination of AGi Adjustment
The AGi Adjustment shall be the quotient obtained by dividing the forecasted balance of the AGi Tracker Account for each member class by the applicable meters in each member class. The AGi Adjustment may be changed annually upon a filing with the Minnesota Public Utilities Commission (Commission). The AGi Adjustment shall apply to bills rendered on and after January 1st of the year.

The AGi Adjustment for each metered retail rate schedule is:

Member Class	Monthly Fixed Charge per Meter
Residential (Schedules 31, 32, 53, 56)	$0.00
Irrigation (Schedule 36)	$0.00
Lighting (Schedule 44-5)	$0.00
Small General (Schedule 41)	$0.00
General (Schedules 46, 54)	$0.00
C&I Interruptible (Schedules 70, 71)	$0.00

Opt-Out Members will not be subject to charges under the Advanced Grid Infrastructure (AGi) Rider, See Section V, Sheet 60.0–6 0.1 for the Advanced Meter Opt-Out (AMO) Rider.

Recoverable AGi Costs shall be the annual revenue requirements associated with AGi capital costs (a) not recovered through base rates, (b) recorded in the AGi Tracker Account for the designated period, and (c) determined by the Commission to be eligible for recovery under this Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the AGi Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the AGi Adjustment shall be credited to the AGi Tracker Account.

True-Up
For each 12-month period ending December 31, a true-up adjustment to the AGi Tracker Account will be calculated reflecting the difference between the AGi Adjustment recoveries and the revenue requirements for such period. The true-up adjustment shall be calculated and included in the AGi recovery filing submitted to the Commission for the following calendar year. No carrying cost shall be applied to the AGi Tracker.

ADVANCED METER OPT-OUT (AMO) RIDER

Applicability

Applicable for residential electric service provided under the Association's metered retail rate schedules for residential members who do not want an advanced, wireless, communicating meter installed at their residence ("Opt-Out Members").

Rate

Advanced Meter Opt-Out Members are subject to a recurring monthly fee after enrollment, regardless of the quantity of meters per premise. The applicable fees for participating in Advanced Meter Opt-Out will be shown as separate line items on the Member's bill as follows:

Monthly Charge	$11.45 per month

The Monthly Charge will be applied following the meter exchange. Where a meter exchange is not required, charges will be applied following affirmative Opt-Out option election or action by the Member as described in the Terms and Conditions.

Opt-Out Members will not be subject to charges under the Advanced Grid Infrastructure (AGi) Rider, See Section V, Sheet 59 for the Advanced Grid Infrastructure Rider.

Terms and Conditions

1. The Cooperative shall have the right to refuse to provide advanced meter opt-out service in either of the following circumstances:
   a) If such a service creates a safety hazard to Members or their premises, the public, or the electric utility's personnel or facilities.
   b) If a Member does not allow the Cooperative's employees or agents access to the meter at the Member's premises.
   c) If the Member has a history of meter tampering.

2. Opt-Out Provisions:
   a) Opt-Out Election: A Member must affirmatively elect to opt-out of having electric consumption metered through an advanced meter to obtain service under this AMO Rider. Members shall default to an advanced meter absent such an election. Members who do not provide reasonable access to their meter or affirmatively prevent the installation of an advanced meter shall be deemed to have elected this AMO Rider.
   b) Frequency of Election: A Member may only enroll in this AMO Rider once per twelve-month period at the same residence.
   c) Opt-In Election: At any time, Opt-Out Members may opt back into electric service with an advanced meter.
   d) Local governments and entities such as condominiums and other multi-unit dwellings are not allowed to exercise the Opt-Out option on behalf of individually metered residents.

ADVANCED METER OPT-OUT (AMO) RIDER
(Continued)

3. Metering Equipment: A non-communicating meter will be used to provide electric service for Members who elect this option.

4. Members enrolled in a load management program or other service requiring an advanced meter will be notified that the Member must discontinue participation in the load management program.

5. Estimated Meter Reading: Opt-Out Members may receive bills based on estimated meter reads if circumstances prevent reading a meter in a given month.

6. Billing: Members will be billed for charges incurred for electric consumption under the applicable metered retail rate schedule, plus the Monthly Charge described in this AMO Rider.

GENERAL RULES AND REGULATIONS

TABLE OF CONTENTS

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way is to be cleared 10 feet on each side of the power line.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a minimum of $500.00 for an extension of 75 feet or less. For extensions longer than 75 feet, the member will be charged $500.00 plus $8.30 per foot for each foot that the extension exceeds 75 feet. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation.

2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.

3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.

4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative's equipment.

5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.

6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.

7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

8. If a member requests an individual residential service extension to a location with no permanent residence, the member will pay the full cost of installation. If a permanent residence is constructed within five (5) years, the member will be refunded the amount less the normal line extension charge at the time the permanent residence is constructed.

9. Dakota Electric Association will not install a transformer within 50 feet of the house. If the closest point of the member's house is within 150 feet of the distribution system in the public right-of-way, the member must install their own secondaries.

Residential Developments (Multiple Lot Plats)

1. To encourage orderly development and to avoid investment in idle facilities, it shall be Dakota Electric Association's policy to examine all residential developments whether served overhead or underground for justification to install electric distribution facilities. When the anticipated revenue justifies the expenditure, Dakota Electric Association will install the facilities at its expense. When the anticipated revenue does not justify the expenditure, the installation will be made only if the developer pays Dakota Electric Association that portion of the facility cost not justified by the anticipated revenue prior to commencement of the electric utility installation.

2. For developments of small lots, one acre or smaller, when underground electric service is desired by a developer or required by a regulatory body or by local ordinance, Dakota Electric Association requires the developer to sign and follow the provisions of the "Residential Underground Distribution Agreement" (RUDA-1).

3. Underground service shall be made available to platted areas with large lots by employing individual transformers for each home. Large lots are defined as being larger than one acre or any lot requiring an individual transformer.

   The developer shall also be subject to a payment in accordance with the provisions of paragraph 1 (Residential Developments) of this policy and as outlined in the Residential Underground Distribution Agreement (RUDA-1) for standard-sized lots.

   Developers of large lot plats must sign and follow the provisions of the Residential Underground Distribution Agreement for Large Lot Developments (RUDA-2).

4. The normal transformer capacity provided for large lot plats will be 15 KVA with additional capacity considered on an individual basis as outlined under paragraph 1, "Individual Overhead Service."

Lighting

The member will be charged for installation costs that exceed allowances specified in the applicable lighting rate schedule.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment Complexes, and Seasonal Accounts

1. Dakota Electric Association will provide overhead or underground, single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and apartment complexes in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the underground primary service to a point of connection designated as either a single-phase or three-phase padmounted transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows:

	Sched. 41 Factors	Sched. 46 Factors	Sched. 70/71 Factors
Estimated Extension Costs			
- Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	$6.25	$5.54
- Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	$0.14779	$0.01959	$0.01326
= Required Contribution in Aid of Construction			

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

The 2000 KVA distribution transformer is the largest size that Dakota Electric Association will install. Multiple transformers and service entrances will be required when service capacity requirements exceed 2000 KVA. The member cannot parallel multiple transformer services without written Dakota Electric approval of the design.

2. Irrigation Members
Dakota Electric Association will provide service to irrigation members in accordance with established applicable irrigation rates and in the "Agreement for Electric Service (Irrigation and Other Seasonal Loads). An economic analysis will be made for extensions to irrigation service. A contribution in aid of construction will be required if the estimated investment is not justified by the anticipated revenue.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

3. Primary Metered Installations
Depending on the configuration of the Dakota Electric primary system, the member may have the option of installing primary metering on the 12.5kV system. Credits for primary service may be available as specified in applicable rate schedules. Many times this option is not available without the installation of additional 12.5kV facilities so as to allow for proper metering and so as not to negatively impact the reliability of other Dakota Electric member loads interconnected with the Dakota Electric distribution system.
   A. The member is responsible for all integration and installation costs for the primary metering system.
   B. The member is responsible for purchasing, owning and operating, all 12.5kV electrical facilities on the member's side of the primary metering installation(s). This includes responsibility for routine and emergency maintenance of those purchased primary facilities, which includes emergency transformer replacement and emergency primary facility repairs.
   C. Primary Metering is required for all primary wires feeding the facilities/complex.
   D. Dakota Electric, the National Electric Code, or both may require special protection for the member's primary system. The member is required to provide any necessary protection. This protection is required to be coordinated with the DEA distribution system's protection.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES

A. Definitions

1. Municipality is defined as any one of the following entities: a county, a city, a township or any other unit of local government.

2. City is defined as either a statutory city or home rule charter city consistent with Minn. Stat. sections 410.015 and 216B.02, subd. 9.

3. Special facilities are defined as non-standard facilities, non-standard design or non-standard location of facilities.

4. Special facilities are the type of services that results in costs in excess of the Association designated service installation. Common examples are duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is adequate, excess capacity, underground installations to wood poles, conversion from overhead to underground service, specific area undergrounding, other special undergrounding, and relocation or replacement of existing Association facilities.

B. General Rule

When requested by the member, group of members, developer, or municipality to provide types of service that result in an expenditure in excess of the Association designated service installation the requesting member, group of members, developer, or municipality will be responsible for such excess expenditure. Common examples of these requests are duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is adequate, excess capacity, capacity for intermittent equipment, trailer park distribution systems, underground installations to wood poles, conversion from overhead to underground, urban renewal undergrounding, other special undergrounding, and relocation or replacement of existing Association facilities.

C. Public Right-of-Way

1. Replacement, Modification or Relocation Due to Construction.

Whenever a governing body that manages a public right-of-way orders the Association to replace, modify or relocate its existing distribution facilities due to construction on said public right-of-way, such facilities will be relocated at Association expense, provided the construction is the most economical, industry accepted installation designated by the Association. If the governing body or municipality requests a type of construction with

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

costs in excess of the Association designated construction, such excess expenditures will be the responsibility of the municipality or the Association's members residing within the municipality. However, if the governing body issuing the order requiring construction on the public right-of-way does not pay the excess cost, the Association may seek Commission approval to recover such excess expenditures from the ratepayers residing in the governing body's territory.

2. Replacement, Modification or Relocation Due to Vacation of Public Right-of-Way.

Whenever a governing body of public right-of-way orders the Association to replace, modify or relocate its existing distribution facilities due to a vacation of a public right-of-way, the Association will be responsible for such expenditure. The Association may request that the governing body pay for the aforementioned expenditure. However, if the governing body chooses not to pay, the Association may seek approval from the Commission to recover this expenditure from the ratepayers residing in the governing body's territory.

D. Construction Requirements for Special Facilities

The Association will initially install special distribution facilities (which may include installation of standard facilities at a location/route deemed non-standard by the company) or the Association will replace, modify or relocate to an Association-approved location/route its existing distribution facilities upon a request of a member, group of members, developer, or upon order or request of a municipality. The benefited member, group of members, developer or municipality will be responsible for all costs in excess of standard installation for new facilities plus the value of the undepreciated life of existing facilities being removed minus the salvage value. However, if the municipality does not pay for the excess expenditure, the Association may seek Commission approval to recover such expenditure from the requesting municipality.

E. Underground Facilities Requirements

The following provisions apply when replacing overhead facilities with underground facilities:

1. The member, at their expense, must engage an electrician to adapt their electrical facilities to accept service from Association underground facilities.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

2. The Association will allow reasonable time for the member to make the necessary alterations to their facilities, before removal of the existing overhead facilities.
3. Perpetual easements will be granted to Association at no cost to the Association whenever any portion of the underground distribution system is located on private land. Said private easements also will allow the Association access for inspection, maintenance, and repair of Association facilities.
4. The Association will have full access to its facilities installed underground for the purpose of inspection, maintenance, and repair of such facilities, such right of access to include the right to open streets and alleys.
5. When undergrounding is the result of a municipal project, the municipality will designate and reserve a definite area within the public ways for the installation and location of Association underground facilities. Once the Association facilities have been installed in such designated and reserved areas, if the municipality requires removal or relocation of such facilities for any reason, the municipality will reimburse the Association for the cost of such removal or relocation. However, if the municipality does not pay for the aforementioned expenditure, the Association may seek approval from the Commission to recover this expenditure from the ratepayers residing in the municipality’s territory.
6. The municipality will give sufficient notice and will allow the Association sufficient time to place its facilities beneath public ways while the same are torn up for resurfacing. The municipality shall provide Association with access to the torn up public ways during such period so that Association will have unobstructed use of sufficiently large sections of the public ways to allow installation of the underground facilities in an economic manner.
7. Secondary voltage service supplied from an underground distribution lateral installation will require that the member install, own, and maintain necessary conduits and secondary service conductors or bus duct to a point designated by Association within or adjacent to the secondary compartment of the transformer or vault. Association will make final connection of member’s secondary service conductors or bus duct to Association’s facilities.
8. Secondary voltage service supplied from underground secondary service conductors may require that the member install, own, or maintain necessary conduits on private property to a point designated by the Association at or near the property line. The secondary service conductors usually will be installed by the member in his conduit,

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

However, in some installations it may be preferred to have Association provide a continuous installation from the Association facilities through the member conduit to his service equipment. In these installations the member must pay the total installed cost of the Association's cable installed on private property. The Association will make the final connection of member's secondary service connectors to Association's facilities.

F. Special Facilities Payments

The requesting party shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment of the facilities. Payments required will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing by the Association. The facilities installed by the Association shall be the property of the Association. Any payment by a member, group of members, developer or municipality shall not entitle him to any ownership interest or rights therein.

Payment for special facilities may be required by either, or a combination, of the following methods as prescribed by the Association: a single charge for the costs incurred or to be incurred by the Association due to such a special installation or a monthly charge being one-twelfth of Association's annual fixed costs necessary to provide such a special installation. The monthly charge will be discontinued if the special facilities are removed. When special distribution facilities are requested by a municipality and payment is not made by the municipality, the Association may seek approval from the Commission to recover its excess expenditure from the municipality's ratepayers.

MEMBER SERVICE INFORMATION
TEMPORARY SERVICE

Temporary service installation will be permitted during the period of construction, remodeling, maintenance, repair, or demolition of buildings, structures, equipment, or similar activities. When installing temporary service to a member, Dakota Electric Association will require that the member bear the cost of the installation and removal of service in excess of any salvage realized.

The member receiving temporary service will be charged the regular rates applicable to the service rendered.

Dakota Electric Association may require that advance payment be made to cover the estimated cost of the temporary service.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS

Meter Reading and Billing Periods

The reading of all meters used for determining charges to members shall be made each month unless otherwise specified by Dakota Electric Association.

The term "month" for meter reading and billing purposes is the period between successive meter readings, which shall be as near as practicable to 30 days.

Dakota Electric Association requires access to meters monthly unless other arrangements are made to obtain monthly meter readings.

If a billing period is longer or shorter than a normal billing period by five (5) days, the billings shall be prorated on a daily basis.

Estimated Billings

When access to a meter cannot be gained, an estimated bill may be rendered. In cases of emergency, the Dakota Electric Association may render estimated bills without reading meters. Estimated bills shall be based on the member's normal consumption for a corresponding period during the preceding months.

Only in unusual cases, or when approval is obtained from the member, shall more than two (2) consecutive estimated bills be rendered.

If an estimated bill seems to be abnormal when a subsequent reading is obtained, the bill, or bills, for the entire estimated period shall be recalculated and a corrected bill generated. If there is reasonable evidence that the use occurred during only one (1) billing period, the bill shall be so computed.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS
(Continued)

Payment of Electric Bills

Residential Members. Residential bills shall be due not less than 25 days from the current billing date. The current billing date shall be no more than three working days before the date of mailing. Balances over $10.00 not received by Dakota Electric by the due date will have a monthly late fee of 1.5 percent or $1.00, whichever is greater, added to the balance.

All Other Members. Bills for all other members shall be rendered monthly and shall be due not less than 15 days from the billing date. The current billing date shall be no more than three (3) working days before the date of mailing. Balances over $10.00 not received by Dakota Electric by the due date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

Payment of Bills by Check

It will be the policy of the Association to accept checks in payment of the electric bill. When a question arises as to the validity of a personal check, cash or money order may be required. No second party or postdated checks will be accepted.

If a check is not honored because of "insufficient funds" or for any other reason, a service charge will be assessed, and the status of the account will be the same as if no payment had been made.

When a payment is made by personal check in order to avoid termination of service, and the check is not honored, service may be disconnected without further notice.

Payment by check or debit card will not be honored for reconnection after disconnection for non-payment. Payment for reconnection after disconnection for non-payment must be made by cash, credit card, or money order.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS
(Continued)

Budget Payment Plan

Dakota Electric Association shall have a budget payment plan available to residential and farm members designed to level monthly billings. The Association will establish a fixed monthly billing based on previous usage. Each monthly bill will show the relationship of budget payments made to the amount due based on actual usage.

Late charges will be assessed to the lesser of the outstanding account balance or the scheduled monthly payment.

Dakota Electric Association will review all budget payment accounts at least annually.

Electronic Funds Transfer

Dakota Electric Association has an Electronic Funds Transfer program (EFT) available to all members. Members may authorize monthly withdrawals for their electric bills directly from their designated financial institutions.

If a presented payment is not honored, late fees and service charges will be billed in accordance with existing policies. EFT can be terminated in writing by either the Association or the member at any time.

Credit Card Payment

Through a third-party vendor, Dakota Electric Association offers all members the option to pay their electric bill by credit card. The member opts to pay a transaction fee based on the amount of the payment. The transaction fee is collected and retained entirely by the third-party vendor.

If a presented payment is not honored, late fees and service charges will be billed to the member in accordance with existing policies.

QuikPay Online Payment

Dakota Electric offers members the option of making either a one-time online payment or regular online monthly payments through “QuikPay”. QuikPay provides multiple payment options. Members may manually enter payments online each month from a checking, savings, or credit card (credit card payments subject to a convenience fee). Members may also have funds automatically deducted from checking or savings accounts.

MEMBER SERVICE INFORMATION
SERVICE CHARGE

When Dakota Electric Association sends a two-man crew or larger to a consumer's premise on a service call outside normal working hours, and they find the trouble is not with Dakota Electric's equipment, a service charge may be assessed.

Every effort to clarify the trouble by telephone shall be made by Dakota Electric Association personnel before they make the trip out to the consumer's premise.

MEMBER SERVICE INFORMATION

Meter Testing

The Cooperative will maintain and test its metering equipment in accordance with the Public Utilities Commission's rules. In the event the Cooperative's test shows a meter to have an average error of more than 2% fast or slow, the Cooperative shall make an adjustment of the bills for service during the period of registration error if known, but not longer than a period of one year. If the period of registration error is not known, the refund or charge for both fast and slow meters shall be based on corrected meter readings for a period equal to one-half the time elapsed since the last test but not to exceed six months. If the amount of the average meter error cannot be determined because of failure of part or all of the metering equipment, the consumer shall pay an amount based upon registration of check metering equipment or an estimated amount based upon the consumer's consumption for comparable operations over a similar period.

If a consumer has called to the Cooperative's attention doubts as to the meter's accuracy and the Cooperative has failed within a reasonable time to check it, there shall be no back billing for the period between the date of the consumer's notification and the date the meter was checked.

Billing Corrections

When a consumer has been overcharged/undercharged as a result of an incorrect reading of the meter, incorrect application of the rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant, or other similar reasons, the amount of the overcharge/undercharge shall be adjusted, refunded, or credited to the consumer as follows:

Remedy for Overcharge:
Dakota Electric shall calculate the difference between the amount collected for service and the amount the Cooperative should have collected for service, plus interest, for the period beginning three years before the date of discovery. Interest will be calculated as prescribed by Minnesota Statutes §325E.02(b). If the recalculated bills indicate that more than $1 is due an existing consumer, or $2 is due a person no longer a consumer of the Cooperative, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the consumer. Refunds to an existing consumer may be in cash or credit on a bill. Credits shall be shown separately and identified. If a refund is due a person no longer a consumer of the Cooperative, the Cooperative shall mail to the consumer's last known address either the refund or a notice that the consumer has three months in which to request a refund from the Cooperative.

Remedy for Undercharge:
Dakota Electric shall calculate the difference between the amount collected for service and the amount the Cooperative should have collected for service for the period beginning one year before the date of discovery. If the recalculated bills indicate that the amount due the Cooperative exceeds $10, the Cooperative may bill the consumer for the amount due. Dakota Electric must not bill for any undercharge incurred after the date of a consumer inquiry or complaint if the Cooperative failed to begin investigating the matter within a reasonable time and the inquiry or complaint ultimately resulted in the discovery of the undercharge. The billing for undercharges shall be separated from the regular bill and the charges explained in detail.

Exception if error date is known:
If the date the error occurred can be fixed with reasonable certainty, the remedy shall be calculated on the basis of payments for service after that date, but in no event for a period beginning more than three years before the discovery of an overcharge or one year before the discovery of an undercharge.

MEMBER SERVICE INFORMATION

General Payment Arrangements

In compliance with Minn. Stat. §216B.098, the Cooperative shall offer a payment agreement for the payment of arrears. Payment agreements will consider a consumer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to continue service to a consumer who has entered and is reasonably on time under an accepted payment agreement.

Undercharges:

a. In compliance with Minn. Stat. §216B.098, the Cooperative shall offer a payment arrangement to consumers who have been undercharged if no culpable conduct by the consumer or resident of the consumer's household caused the undercharge. The agreement may cover a period equal to the time over which the undercharge occurred, or a different time period that is mutually agreeable to the consumer and the Cooperative, except that the duration of a payment agreement offered by the Cooperative to a consumer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the consumer's household.

b. No interest or delinquency fee will be charged for payment arrangements resulting from under charges.

c. If a consumer inquiry or complaint results in the Cooperative's discovery of the undercharge, the Cooperative may bill for undercharges incurred after the date of the inquiry or complaint only if the Cooperative began investigating the inquiry or complaint within a reasonable time after when it was made.

Medically Necessary Equipment

The Cooperative shall reconnect or continue service to a consumer's residence where a medical emergency exists, or where medical equipment requiring electricity necessary to sustain life is in use, provided that the Cooperative receives: (1) written certification, or initial certification by telephone and written certification within five business days, from a medical doctor that failure to reconnect or continue service will impair or threaten the health or safety of a resident of the consumer's household; and (2) the consumer's consent to a payment arrangement for the amount in arrears. Certification must be renewed annually. Because some interruptions in service are unavoidable and in some cases may last longer than some members can be without power, we urge members with special medical needs to make necessary arrangements for auxiliary power for any vital life-support equipment.

MEMBER SERVICE INFORMATION
DISCONNECTION OF SERVICE

Disconnection Without Notice
Without notice Dakota Electric may disconnect service to any consumer:

A. in the event of an unauthorized use of or tampering with the Association's equipment; or
B. in the event of a condition determined to be hazardous to the consumer, to other members of the Association, to the Association's equipment, or to the public.

Unlawful Use of Service
In any case of tampering with meter installation or interfering with the proper functioning thereof or any other unlawful use or diversion of service by any person, or evidence of any such tampering, interfering, unlawful use or service diversion, consumer is liable to immediate discontinuance of service, without notice, and to prosecution under applicable laws, and Association shall be entitled to collect from consumer at the appropriate rate for all power and energy not recorded on the meter by reason of such tampering, interfering, or other unlawful use or service diversion (the amount of which may be estimated by Association from the best available data), and also for all expenses incurred by the Association on account of such unauthorized act or acts.

Disconnection for Nonpayment
<u>All Accounts</u>
Dakota Electric shall credit all payments received against the oldest outstanding account balance before the application of any late charge.

<u>Residential Accounts</u>
In the case of a resident on either a budget billing plan or a payment schedule, delinquent amount means the lesser of the outstanding account balance or the outstanding scheduled payments. To avoid disconnecting residential accounts as much as possible, Dakota Electric will advise delinquent residential members of the various alternatives available to them, such as protection of the Cold Weather Rule when applicable (see below) and the various assistance programs available through state and local agencies. When no satisfactory payment schedule can be agreed to or maintained, Dakota Electric will proceed with disconnection. The schedule will be as follows:

Balances over $10.00 not received by Dakota Electric at the time of the next scheduled billing date (approximately 30 days after initial billing and never less than 25 days later) will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance. A disconnect notice may be sent shortly after the second bill is mailed. Disconnection will be scheduled for not less than five (5) days after the date of the disconnect notice. At the time of disconnection, the residential account will have unpaid use of electricity for not less than 50 days.

<u>Commercial and Irrigation Accounts</u>
Balances over $10.00 not received by Dakota Electric at the time of the next scheduled billing date (approximately 30 days after initial billing and never less than 25 days later) will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance. A disconnect notice will be sent shortly after the second bill is mailed. Disconnection will be scheduled for five (5) days after the date of the disconnect notice. At the time of disconnection, the commercial account will have unpaid use of electricity for approximately 50 days.

MEMBER SERVICE INFORMATION
DISCONNECTION OF SERVICE

Notice of Disconnection

Dakota Electric Association shall send notices to disconnect service by first class mail. A specific date will be given for the time when a payment must be received or service may be disconnected.

If Dakota Electric Association is not contacted by the consumer, at least one attempt will be made to contact the consumer by telephone. If no contact is made, an Association employee will make a final attempt to contact the consumer at the place of service, and if no contact is made, or if contact is made but no payment agreement can be reached, service may be disconnected.

Reconnection of Service

In the event that service has been disconnected because of nonpayment of the electric bill, service charges, based on the cost to restore service will be assessed before service is restored. This cost will necessarily be higher during an overtime period.

If service has been disconnected, payment must be in the office before the order will be given to restore service. Cash or money order may be required at any time. Dakota Electric will not restore service until all arrears are paid in full and a deposit is made by cash, credit card, or money order according to the Association's deposit requirements, or until other satisfactory credit arrangement is made.

In the event the order has been issued to disconnect service, and the collector arrives at the premises, he/she must accept cash, credit card, or money order payment of the delinquent bill. This payment will avoid the necessity of terminating service.

Notice to Cities of Utility Disconnection

Upon written request from a statutory or home rule charter city and consistent with Minnesota Statute 216B.0976, the Cooperative will provide reports of currently disconnected properties or newly disconnected properties for consumers located within the city's boundaries.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: VI
SHEET: 14.0
REVISION: Original

DISCONNECTION DURING COLD WEATHER
(Page 1 of 6)

1. Scope

This section applies only to residential consumers of the Cooperative.

2. Definitions

The following definitions apply in this section:

1. "**Cold weather period**" means the period from October 15 through April 15 of the following year.
2. "**Consumer**" means a residential consumer of the Cooperative.
3. "**Disconnection**" means the involuntary loss of utility heating service as a result of a physical act by the Cooperative to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts utility service in any way.
4. "**Household income**" means the combined income, as defined in section 290A.03, subdivision 3, of all residents of the consumer's household, computed on an annual basis. Household income does not include any amount received for energy assistance.
5. "**Reasonably timely payment**" means payment within five working days of agreed-upon due dates.
6. "**Reconnection**" means the restoration of utility heating service after it has been disconnected.
7. "**Summary of rights and responsibilities**" means a notice approved by the Minnesota Public Utilities Commission that contains, at a minimum, the following:
    a) an explanation of the provisions of Section 5 and Minn. Stat. 216B.096, subd. 5;
    b) an explanation of no-cost and low-cost methods to reduce the consumption of energy;
    c) a third-party notice;
    d) ways to avoid disconnection;
    e) information regarding payment agreements;
    f) an explanation of the consumer's right to appeal a determination of income by the Cooperative and the right to appeal if the Cooperative and the consumer cannot arrive at a mutually acceptable payment agreement; and
    g) a list of names and telephone numbers for county and local energy assistance and weatherization providers in each county served by the Cooperative.

DAKOTA ELECTRIC ASSOCIATION | SECTION: VI
4300 220th Street West | SHEET: 14.1
Farmington, MN 55024 | REVISION: Original

DISCONNECTION DURING COLD WEATHER
(Page 2 of 6)

1. "**Third-party notice**" means a Minnesota Public Utilities Commission-approved notice containing, at a minimum, the following information:
   a) a statement that the Cooperative will send a copy of any future notice of proposed disconnection of Cooperative service to a third party designated by the residential consumer;
   a) instructions on how to request this service; and
   b) a statement that the residential consumer should contact the person the consumer intends to designate as the third-party contact before providing the Cooperative with the party's name.
2. "**Cooperative**" means Dakota Electric Association.
3. "**Utility heating service**" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the consumer's primary residence.
4. "**Working days**" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing of a notice shall not be counted in calculating working days.

3. Cooperative obligations before cold weather period

Each year, between September 1 and October 15, the Cooperative must provide all consumers, personally or by first class mail, a summary of rights and responsibilities. The summary must also be provided to all new residential consumers when service is initiated.

4. Notice before disconnection during cold weather period

Before disconnecting utility heating service during the cold weather period, the Cooperative must provide, personally or by first class mail, a Minnesota Public Utilities Commission-approved notice to a consumer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of rights and responsibilities.

DISCONNECTION DURING COLD WEATHER
(Page 3 of 6)

5. Cold weather rule

During the cold weather period, the Cooperative may not disconnect and must reconnect utility heating service of a consumer whose household income is at or below 50 percent of the state median income if the consumer enters into and makes reasonably timely payments under a mutually acceptable payment agreement with the Cooperative that is based on the financial resources and circumstances of the household; provided that, the Cooperative may not require a consumer to pay more than ten percent of the household income toward current and past utility bills for utility heating service.

The Cooperative may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the consumer.

The consumer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the consumer's financial circumstances have changed or the consumer is unable to make reasonably timely payments.

The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the consumer and the Cooperative.

The Cooperative shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration consumer availability, employee availability, and construction-related activity.

6. Verification of income

In verifying a consumer's household income, the Cooperative may:

(1) accept the signed statement of a consumer that the consumer is income eligible;

(2) obtain income verification from a local energy assistance provider or a government agency;

(3) consider one or more of the following:

a) the most recent income tax return filed by members of the consumer's household;
b) for each employed member of the consumer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;

DISCONNECTION DURING COLD WEATHER
(Page 4 of 6)

a) documentation that the consumer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension provider;
b) a letter showing the consumer's dismissal from a job or other documentation of unemployment; or
c) other documentation that supports the consumer's declaration of income eligibility.

A consumer who receives energy assistance benefits under any federal, state, or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

7. Prohibitions and requirements

This section applies during the cold weather period.

The Cooperative may not charge a deposit or delinquency charge to a consumer who has entered into a payment agreement or a consumer who has appealed to the Minnesota Public Utilities Commission under Section 8 and Minn. Stat. 216B.096, subd. 8.

The Cooperative may not disconnect service during the following periods:

(1) during the pendency of any appeal under Section 8 and Minn. Stat. 216B.096, subd. 8;

(2) earlier than ten working days after the Cooperative has deposited in first class mail, or seven working days after the Cooperative has personally served, the notice required under Section 4 to a consumer in an occupied dwelling;

(3) earlier than ten working days after the Cooperative has deposited in first class mail the notice required under Section 4 and Minn. Stat. 216B.096, subd. 4 to the recorded billing address of the consumer, if the Cooperative has reasonably determined from an on-site inspection that the dwelling is unoccupied;

(4) on a Friday, unless the Cooperative makes personal contact with, and offers a payment agreement consistent with this section to the consumer;

(5) on a Saturday, Sunday, holiday, or the day before a holiday;

(6) when Cooperative offices are closed;

DISCONNECTION DURING COLD WEATHER
(Page 5 of 6)

(7) when no Cooperative personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service; or

(8) when the Minnesota Public Utilities Commission offices are closed.

The Cooperative may not discontinue service until the Cooperative investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the Cooperative to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the Cooperative must attempt a second contact during nonbusiness hours. If personal contact is made, the Cooperative representative must provide notice required under Section 4 and Minn. Stat. 216B.096, subd. 4 and, if the Cooperative representative is not authorized to enter into a payment agreement, the telephone number the consumer can call to establish a payment agreement.

The Cooperative must reconnect utility service if, following disconnection, the dwelling is found to be occupied and the consumer agrees to enter into a payment agreement or appeals to the Minnesota Public Utilities Commission because the consumer and the Cooperative are unable to agree on a payment agreement.

8. Disputes; consumer appeals

The Cooperative must provide the consumer and any designated third party with a Minnesota Public Utilities Commission-approved written notice of the right to appeal:

(1) a Cooperative determination that the consumer's household income is more than 50 percent of state median household income; or

(2) when the Cooperative and consumer are unable to agree on the establishment or modification of a payment agreement.

A consumer's appeal must be filed with the Minnesota Public Utilities Commission no later than seven working days after the consumer's receipt of a personally served appeal notice, or within ten working days after the Cooperative has deposited a first class mail appeal notice.

DISCONNECTION DURING COLD WEATHER
(Page 6 of 6)

Notwithstanding any other law, following an appeals decision adverse to the consumer, the Cooperative may not disconnect utility heating service for seven working days after the Cooperative has personally served a disconnection notice, or for ten working days after the Cooperative has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

9. Consumers above 50 percent of state median income

During the cold weather period, a consumer whose household income is above 50 percent of state median income:

(1) has the right to a payment agreement that takes into consideration the consumer's financial circumstances and any other extenuating circumstances of the household; and

(2) may not be disconnected and must be reconnected if the consumer makes timely payments under a payment agreement accepted by the Cooperative.

The second sentence of Section 7 does not apply to consumers whose household income is above 50 percent of state median income.

10. Reporting

Annually on November 1, the Cooperative must electronically file with the Minnesota Public Utilities Commission a report, in a format specified by the Minnesota Public Utilities Commission, specifying the number of utility heating service consumers whose service is disconnected or remains disconnected for nonpayment as of October 1 and October 15. If consumers remain disconnected on October 15, the Cooperative must file a report each week between November 1 and the end of the cold weather period specifying:

(1) the number of utility heating service consumers that are or remain disconnected from service for nonpayment; and

(2) the number of utility heating service consumers that are reconnected to service each week. The Cooperative may discontinue weekly reporting if the number of utility heating service consumers that are or remain disconnected reaches zero before the end of the cold weather period.

The data reported under this Section and Minn. Stat. 216B.096 are presumed to be accurate upon submission and must be made available through the commission's electronic filing system.

MEMBER SERVICE INFORMATION
DEPOSITS

It will be the policy of Dakota Electric Association to collect a deposit not to exceed an estimated two months' gross bill or existing two months' average bill where applicable if the service has been terminated because of nonpayment or when a bankruptcy is filed. Any existing deposit must be applied to the delinquent bill, and then the new deposit will be assessed and must be paid prior to the time the service is restored.

When a member returns to Dakota Electric Association after leaving with an unpaid balance or other credit problems, a deposit equal to two average months' electric bills of the most recent occupant at that address may be assessed. This deposit is in addition to payment in full for the previously unpaid balance.

Dakota Electric shall not require a deposit for a new member with no prior service from the Association unless the credit history of the new member demonstrates that payment cannot be assured. The determination of the new member's credit history shall be made only by credit reports reflecting the purchase of utility service, unless permission in writing is received from the new member to use other credit reports, and such reports mailed to the new member. Refusal of a new member to permit use of a credit rating or credit service, other than that of a utility, shall not affect the Association's determination of that new member's credit history. Satisfactory credit shall be 12 consecutive months of on-time payments with no remaining unpaid balance.

If a member has maintained a good payment record for one year, the deposit will be refunded. A good payment record is defined as payment of the electric bill within 25 days of the due date each of the preceding 12 months.

Deposits shall earn interest at an annual rate as specified by Minnesota Statute 325E.02. This interest will be credited to the electric bill printed in December or will be credited to the final bill, whichever occurs first.

Deposits, plus interest, will be applied to the final bill, and any credit balance remaining will be refunded within forty-five (45) days from the date service is terminated.

Dakota Electric shall not require a deposit of any member without explaining in writing why that deposit or guarantee is required.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM

Any Dakota Electric Association member allowing Demand-Side Management (DSM) controls on approved interruptible loads will receive an off-peak energy kilowatt-hour and/or demand kilowatt charge for that electricity as listed in the rates.

General Rules and Policies

1. Dakota Electric Association shall supply additional meters and the DSM receivers at no cost to the member. All other requirements, such as the meter sockets, wiring, and installation shall be the responsibility of the member. The DSM receivers will remain the property of Dakota Electric Association. Only authorized DEA employees shall have the authority to break the seals for any reason, including repair of the DSM receivers or metering equipment.
2. DSM receivers and submeters shall be mounted adjacent to the existing kilowatt-hour meter. The meter shall be mounted on the outside of the building and shall be accessible to the Association at all times and comply with the Association meter socket requirements. Any alternate locations must be approved by the Association prior to installation.
3. Dakota Electric will make a final inspection after all of the necessary work has been done. At that time, if all equipment is functioning properly, the second meter will be installed, if required, and the controlled rate will apply. All installations must have an electrical inspection affidavit filed with the Minnesota State Board of Electricity and DEA.
4. All trouble calls dealing with the controlled loads shall be made to DEA. DEA will determine whether to send out a DEA service technician or request that the member call a service company on his/her own behalf. If the member's service technician determines that DEA's DSM receiver was malfunctioning and a DEA service technician verifies that, Dakota Electric Association will reimburse the member for the service call. If the problem is with the member's wiring or equipment, then the member will be responsible for costs incurred which may include a Load Management Service Charge.
5. All members with DSM-controlled loads shall allow periodic inspections of the controlled loads by Dakota Electric.
6. If any part of the controlled system is tampered with, the member is subject to being removed from the controlled rate for at least one (1) year.
7. Eligibility of participating loads will be guided by Great River Energy program requirements.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Controlled Water Heaters

1. The member may choose to have service under either Schedule 51, "Controlled Energy Storage," or Schedule 52, "Controlled Interruptible Service."

2. Under Schedule 51, "Controlled Energy Storage":
   a. Typically, the water heater will be energized from 11 p.m. to 7 a.m.
   b. There is no restriction on the size of the water heater, but Dakota Electric recommends an energy factor of .90 or greater and a minimum capacity of 80 gallons and larger capacity when usage and/or family size requires. DEA will assist members with sizing water heaters.
   c. All kilowatt-hours shall be submetered. If the member has other qualifying loads, these kilowatt-hours may be combined on one meter.

3. Under Schedule 52, "Controlled Interruptible Service":
   a. The member should recognize that the water heater may be off daily for extended periods, and this may result in occasional lack of sufficient hot water. The member must have an electric water heater with a minimum capacity of at least 40 gallons. Dakota Electric recommends an energy factor of .90 or greater.
   b. All kilowatt-hours shall be submetered, where feasible, or a monthly credit will be given, as listed in Schedule 52, at DEA's option. If the member also has a dual fuel heating installation, these kilowatt-hours may be combined on one submeter.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Interruptible Installations

1. Schedule 52, “Controlled Interruptible Service,” is available to members who use electricity as a heating source or other qualifying loads. Connected fixed electric space heating must be sized according to space heating requirements. Cord and plug electric space heating does not qualify.

2. Dakota Electric Association requires that a backup heat source capable of keeping the residence at a minimum of 55 degrees be present. Dakota Electric does not specify what the heat source should be except that it shall not be uncontrolled electric heat.

3. Heat pumps qualify for the interruptible rate. All electric resistance heat associated with the heat pumps must also be controlled. Heat pumps will be controlled both winter and summer in accordance with Dakota Electric’s load control requirements.

4. All kilowatt-hours shall be submetered. If the member also has a water heater or other interruptible load on Schedule 52, these kilowatt-hours may be combined on one submeter. If the member has both Interruptible and Storage loads these loads may be combined under the rate schedule with the largest load.

Energy Storage Installations

1. Schedule 51, “Controlled Energy Storage,” is available to members who normally use electricity between 11 p.m. and 7 a.m. (or as established by the Association) to charge equipment which will retain the energy for use during the remaining hours. Water, ice, slab storage, storage bricks, storage batteries, or other materials that qualify may be used for energy storage.

2. All kilowatt-hours shall be submetered. If the member also has a water heater or other energy storage load on Schedule 51, these kilowatt-hours may be combined on one submeter. If the consumer has both Interruptible and Storage loads, these loads may be combined under the rate schedule with the largest load.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Irrigation Loads

1. The controlled rate, as listed under Schedule 36, "Irrigation Service," is available to members who have DSM equipment installed. New installations may qualify for this rate when installed.

2. Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

3. The Demand-Side Management receivers will interrupt power to the pump motor, and the motor will require manual restart. Any additional equipment necessary to shut down other parts of the irrigation system must be installed by the member at their cost.

4. The typical number of hours to be controlled during any 24-hour period will be approximately six (6) hours. It may be longer based on electric system requirements.

Controlled Central Air Conditioners

1. The member may choose to have service under Schedule 80, "Cycled Air Conditioning Service," Schedule 51, "Controlled Energy Storage," or Schedule 52, "Controlled Interruptible Service,"
2. Under Schedule 80 "Cycled Air Conditioning Service"
   a. For members without other interruptible or controllable loads, such as an electric water heater, electric heat, heat pump, etc.
   b. The central air conditioner will be cycled on and off when a peak or critical situation is reached.
   c. Energy consumption may be submetered.
   d. The member should recognize that the central air conditioner may be cycled for extended periods and this may result in a temperature rise within the home.
3. Under Schedule 51 "Controlled Energy Storage" or Schedule 52 "Controlled Interruptible Service"
   a. All kilowatt-hours will be submetered. If the member also has an interruptible water heater or heat installation, these kilowatt-hours may be combined on one submeter.
   b. The central air conditioner will be cycled on and off when a peak or critical situation is reached.
   c. The member should recognize that the central air conditioner may be cycled for extended periods and this may result in a temperature rise within the home.

MEMBER SERVICE INFORMATION
STANDBY SERVICE RIDER

STANDBY, SUPPLEMENTARY, EMERGENCY AND INCIDENTAL SERVICES

Unless otherwise specifically provided, the Association's rate schedules require that the member will take their entire electrical requirements from the Association. The Association's service is not available for standby, supplementary, emergency or incidental service with respect to any other source of power except when contracted for under a rate schedule providing for these services.

A. Definitions:

1. Standby service is defined as service continuously available through a permanent connection to provide power and energy for use by a member in case of failure of another mechanical or electrical source of power.
2. Supplementary service is defined as service continuously available through a permanent connection to supplement or augment directly or indirectly another independent source of power.
3. Emergency service is defined as service supplied through a temporary connection for the member's use when their usual source of supply has failed.
4. Incidental service is defined as service continuously available through a permanent connection to provide power and energy for use by a member where such use is merely incidental to members operations and essentially for their convenience; e.g. (without limiting the generality of the foregoing), for voltage or frequency control, for partial lighting of selected or limited areas, or for the operation of controls, battery chargers, starting devices, electric clocks, or other equipment requiring relatively small quantities of energy as compared with member's total energy usage.

B. Parallel Operations. If a member has an independent source of power that will be operated in parallel with the Association's system, such source of power must be operated as provided below. Any member who operates their facility in non-compliance with these provisions will be subject to immediate discontinuance of service.

MEMBER SERVICE INFORMATION
STANDBY SERVICE RIDER
CONTINUED

1. No member may connect an independent source of power in parallel with the Association's system without prior written consent of the Association. Any member desiring to generate in parallel shall execute a contract with the Association that contains terms and provisions regarding metering, billing, technical and operating parameters for the member's independent source of power.

2. The interconnection of member's facilities with the Association's system shall not interfere with the quality of the Association's service to any of its other members.

3. The member will provide the necessary equipment as approved by the Association to enable the member to operate their independent source of power in parallel with the Association's system. The member's independent source of power will be designed so that the interconnection circuit breaker or load break switch between the Association and the member will open under the following conditions:

   a. De-energized Association system
   b. Sustained line faults on Association's system
   c. Faults on member's system

A member shall consult with the Association regarding these minimum requirements, additional protection recommended, proper operation of interconnect circuit breaker or load break switch, and member's independent source of power disconnecting device.

4. Since the power factor and the voltage at which the Association's system and a member's system are operated will vary, each party agrees to operate their system at a power factor as near unity as possible in such manner as to absorb their share of the reactive power, and voltage as conducive to the best operating standards.

5. The Association reserves the right to discontinue service if continued parallel operation by the member results in trouble on the Association's system, such as interruptions, ground faults, radio or telephone interference, surges, or objectionable voltage fluctuations, where such trouble is caused by a member and the member fails to remedy the causes thereof within a reasonable time.

MEMBER SERVICE INFORMATION
INTERRUPTIBLE SERVICE (SCHEDULES 70 AND 71)

A. General Rules and Policies for Interruptible Service (Schedules 70 and 71)

Participation in interruptible service, with or without a generator, must comply with the following requirements as applicable. If a generation system is used for curtailing a member's electrical requirements, the generation interconnection must comply with the requirements specified in the "Dakota Electric Association Distributed Generation Interconnection Requirements" document. The process for interconnecting with the Dakota Electric systems is documented in the "Distributed Generation Interconnection Process" document. Both the technical requirements and process documents follow the State of Minnesota Distributed Generation Interconnection standards. These document requirements include, but are not limited to the following.

1. The member is responsible for reducing load from electrical service provided by the Association during control periods to be eligible for an interruptible rate.
2. The Association will make every effort to give the member one-half hour notice prior to the start of a control period, but it is not guaranteed. Notices will be given in the form of an email, text message, or load control signal.
3. The duration and frequency of control periods shall be at the discretion of the Association. Control periods will normally occur at such times when the Association expects peak load conditions or when, in the Association's opinion, the reliability of the system is endangered.
4. The member is obligated to remain on the Interruptible rate for a minimum period of one year.
5. For Schedule 71 only, field tests will be conducted during normal peak demand hours to determine the amount of controllable demand and thereby establish the initial coincidental demand level for billing purposes.
6. The minimum controllable demand to qualify for this service shall be 50 kW.
7. The Association shall not be liable for any loss or damage caused by or resulting from testing any other interruption of service.
8. The member must allow the Association to inspect and test the load control installation and equipment provided by the member.
9. The member must notify the Association of any modifications or changes that are made to the original load control installation and equipment provided by the member.

   The Association will supply a single dry contact to a member to initiate the load control. The member is responsible for any wiring from the Association provided dry contact to the member owned equipment. The member must provide and maintain a dial in direct (DID) telephone line to the Association's metering equipment. (PBX DID lines are acceptable.) The exact location of the phone line shall be verified with the Association. Alternatively, the member may select cellular meter and pay applicable communication fee.
10. Generator must be available for control at all times or the member will/may be removed from the rate, unless prior written approval is given by Dakota Electric.

MEMBER SERVICE INFORMATION
INTERRUPTIBLE SERVICE (SCHEDULES 70 AND 71)
(Continued)

B. General Rules and Policies for Distributed Generation Interconnection

1. The generation system installation must meet all of the applicable local and national standards for generation interconnection as well as the Dakota Electric Association Distributed Generation Interconnection Requirements. Any member that operates their generation system in non-compliance with these interconnection requirements will be subject to discontinuance of service. Current interconnection documents are available on the Association's Web site at http://light.dakotaelectric.com/Handbook/Pages1/Interconnecting Generation.aspx. The main topics covered in the Interconnection Requirements document include, but are not limited to:
    a. Types of Interconnection
    b. Interconnection Issues and Technical Requirements
    c. Generation Metering, Monitoring, and Control
    d. Protective Devices and Systems
    e. Agreements
    f. Metering Requirements

2. The member is responsible for all status point wiring from the on-site generation system to the Association's monitoring equipment. The generation status points typically include but are not limited to:
    a. Generator and Utility switch or breaker positions
    b. Generator Status – running or not running
    c. Generator Trouble Alarm Status
    d. Lock Out Relay Status – if applicable

3. The member retains responsibility for compliance with local and national standards in addition to the Dakota Electric Interconnection Requirements as they may change over time. No consumer may connect on-site generation in parallel with the Association's system without prior written consent of the Association.

4. The interconnection of member's facilities with the Association's system shall not interfere with the quality of the Association's service to any of its other members.

5. The member's operation of on-site generators, shall be restricted to control periods, periodic maintenance, equipment testing, severe weather conditions, and power supply outages only.

6. The generator fuel supply must be adequate for at least ten (10) hours of operation at full load. The Association recommends a fuel supply of at least 24 hours to cover normal daily loads.

7. The Association's operation of the member's generation or curtailment systems will normally be during control periods, but the Association reserves the right to further control on-site generators or curtailment systems as needed to promote efficient and reliable operation of the Association's system.

8. The member will provide the necessary equipment as approved by the Association to enable the member to operate the on-site generation in parallel with the Association's system as specified in Dakota Electric Association's Interconnection Requirements document.

9. The Association reserves the right to discontinue service if continued parallel operations by the member results in trouble on the Association's system, such as interruptions, ground faults, radio or telephone interference, surges, or objectionable frequency and voltage fluctuations, where such trouble is caused by a member, and the member fails to remedy the causes thereof within a reasonable time.

Docket No. E-111/GR-19-478

Exhibit__(DEA-16)
Residential Time of Use
Rate Analysis

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Residential Billing Determinants & COS Results

Residential Billing Determinants

100,235	Consumers
838,684	Energy Sales - All (MWh)
281,636	Energy Sales - On-Peak (MWh)
557,048	Energy Sales - Off-Peak (MWh)

Summary of Residential Revenue Requirements

	Power Supply
	Wholesale Power
10,370,341	Demand Related - Summer
5,458,423	Demand Related - Winter
4,952,367	Demand Related - Other
20,781,131	Subtotal - Demand
-	Energy Related - Critical Peak
17,333,391	Energy Related - On-Peak
26,723,916	Energy Related - Off-Peak
44,057,307	Subtotal Energy
	Revenue Related
64,838,438	Subtotal - Wholesale
	Allocated Overhead & Margin
-	Direct Related
-	Revenue Related
198,146	Demand Related
420,872	Energy Related
619,018	Subtotal - Allocated
65,457,456	Subtotal - Power Supply
	Transmission
-	Direct Assigned
13,696,762	Demand Related
-	Energy Related
13,696,762	Subtotal - Transmission
	Allocated Overhead & Margin
-	Direct Related
-	Revenue Related
-	Demand Related
-	Energy Related
-	Subtotal - Allocated
13,696,762	Subtotal - Transmission
	Distribution
3,010,588	Dist. Sub. - Capacity
-	Dist. Sub. - Consumer
6,733,215	Primary Line - Capacity
11,552,938	Primary Line - Consumer
369,821	Line Transf. - Capacity
1,946,450	Line Transf. - Consumer
165,079	Sec. & Serv.
5,150,000	Meter
11,393,185	Acct. & Serv.
-	Revenue Related
-	Direct Assigned
40,321,276	Subtotal - Distribution
3,608,460	Additional TOU Metering
123,083,954	**Total**

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Cost Assignment

Residential Distribution Revenue

	15,636,660	Fixed Charge Revenue
	28,912,094	Energy Revenue
	44,548,754	Distribution Total
$	0.03450	Distribution Revenue per kWh

	Transmission	*D-Summer*	*D-Winter*	*D-Spr/Fall*	*Energy - CP*	*E - On-Peak*	*E - Off-Peak*	*Total*
On-Peak Summer	4,080,601	9,506,146			-	2,722,337	1,231,580	17,540,664
On-Peak Winter	3,011,023		5,003,554			2,242,233	1,030,336	11,287,145
On-Peak Spr/Fall	5,463,742			4,539,670		4,080,950	1,906,150	15,990,512
Int Peak	1,141,397	864,195	454,869	412,697		8,287,871	3,686,195	14,847,224
Off-Peak							18,869,655	18,869,655
	13,696,762	10,370,341	5,458,423	4,952,367	-	17,333,391	26,723,916	78,535,200

	GRE On-Peak Energy	*GRE Off-Peak Energy*
On-Peak Summer	15.7%	4.6%
On-Peak Winter	12.9%	3.9%
On-Peak Spr/Fall	23.5%	7.1%
Int Peak	47.8%	13.8%
Off-Peak		70.6%
	100.0%	100.0%

Coincident Demand

Summer	608.3	32.5%
Winter	448.9	24.0%
Other	814.5	43.5%
	1871.8	100.0%

Dakota Electric Association
Residential TOU Rate (Schedule 56)
kWh Billing Unit Estimates

Test Year Forecast (2019)

Month	kWh	%		
1	753	9.0%		
2	623	7.4%	25.5%	25%
3	618	7.4%		
4	533	6.4%	21.0%	21%
5	604	7.2%		
6	765	9.1%		
7	975	11.7%	31.0%	31%
8	854	10.2%		
9	659	7.9%		
10	619	7.4%	22.6%	23%
11	610	7.3%		
12	756	9.0%		
	8,369	100.0%		

Rate 31 Energy Sales

Summer	257,025,312	30.7%	30%
Other	581,064,216	69.3%	70%
	838,089,528		

Hours

On-Peak (3 - 11)	23.8%	25%
Int Peak (7 - 3)	23.8%	25%
Off-Peak (11 - 7)	52.4%	50%
	100.0%	100%

Period Hours & kWh Billing Unit Estimates

On-Peak Summer	8.2%	68,882,180
On-Peak Winter	6.8%	57,053,538
On-Peak S/F	12.5%	104,468,100
Int Peak	24.9%	208,412,955
Off-Peak	47.6%	399,272,755
	100%	838,089,528

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Rate Design

Rate Design

Fixed Charge	100,235	cons.	$	13.00	15,636,660
Energy Charge					
Peak Period					
Summer	68,882,180	kWh	$	0.289	19,916,935
Winter	57,053,538	kWh	$	0.232	13,255,357
Spring/Fall	104,468,100	kWh	$	0.188	19,594,413
Int. Period	208,412,955	kWh	$	0.106	22,036,975
Off-Peak Period	399,272,755	kWh	$	0.082	32,643,615
	838,089,528	kWh	Total		123,083,954

Definitions:
Summer = June, July, Aug
Winter = Dec, Jan, Feb
Spring/Fall = Mar. Apr, May, Sept, Oct, Nov
Peak Period = 3 pm to 11 pm M-F excl holidays
Intermediate Peak = 7 am to 3 pm M-F excl holidays
Off-Peak = all other hours

Docket No. E-111/GR-19-478

Exhibit__(DEA-15)
EV Rate Analysis

Dakota Electric Association
Residential Electric Vehicle Rate
Wholesale Power Costs

1. Assumptions

2.5% Distribution Line Loss

80% Coincidence Factor

Level 2 Charger

6.6	kW Demand
2.9	Hours to Full Charge
10.96	kWh Energy per Day

2. Wholesale Power Rates (GRE 2019)

Energy Charge			
Off Peak Energy Rate	@	$0.04646	/kWh
On Peak Energy Rate	@	$0.05939	/kWh
Critical Peak Energy Rate	@	$0.05939	/kWh
Capacity Charge			
Summer (Jun-Aug)	@	$18.24	/kW/mo.
Winter (Dec-Feb)	@	$12.16	/kW/mo.
Other	@	$6.08	/kW/mo.
Average		$10.64	
Transmission Charge	@	$6.57	/kW/mo.
Ancillary Charge	@	$0.69	/kW/mo.
	@	$0.00009	/kWh

3. Annual Energy

12,000	Annual Miles per Year
3.65	Average Miles per kWh
3,288	Annual Energy (kWh)

4. Peak Charging

Level 2:

Demand (charging from 4 pm to 9 pm):

6.6	kW Demand
80%	Coincidence Factor
5.28	Diversified Demand
$ 17.90	Average Monthly Coincident Charges per kW
$ 94.51	Subtotal
12	Months
$ 1,134.14	Subtotal
2.5%	Line Loss
$ 1,162.50	Annual Demand Cost

Summary of Cost of Service Analysis
Load Management Rates

I. Summary

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Rate Description	**GRE Rate** (¢/kWh)	**Line Losses** (¢/kWh)	**Meter & Control** (¢/kWh)	**Allocated Distribution** (¢/kWh)	**Margin** (¢/kWh)	**Total Cost** (¢/kWh)	**Weighted Sales** (%)	**Retail Rate** (¢/kWh)
Schedule EV-1								
Residential Electric Vehicle	4.655	0.116	0.420	2.130	0.236	7.56	100%	**7.56**

Col.	**Notes**
(b)	Based on GRE wholesale rate schedules for Year 2019, off peak energy rate plus ancillary service energy charge.
(c)	GRE General Service Energy Rate x 2.5% which represents the average losses for the system.
(d)	Average annual cost per kWh from load management analysis.
(e)	Allocated distribution cost from load management analysis.
(f)	Margin percent times sum of Col. (b) to Col. (e).
(g)	Sum Col. (b) to Col. (f).

Dakota Electric Association
Residential Electric Vehicle Rate
Rate Design

Line				
	Off-Peak			
1		$	0.0756	Page 2 of 3
	On-Peak			
2		$	0.0756	Off-Peak Energy Charge
3		$	0.05939	Wholesale On-Peak Energy (see Page 1 of 3)
4	-	$	0.04646	Wholesale Off-Peak Energy (see Page 1 of 3)
5	=	$	0.01293	Additional Cost of On-Peak Wholesale Energy
6		$	1,162.50	Annual Demand Cost (see Page 1 of 3)
7	÷		3,288	Annual Energy - kWh (see Page 1 of 3)
8	=	$	0.35356	Demand Cost per kWh
9		$	0.4421	Total On-Peak Rate (sum of lines 2, 5 and 8)

Present Billed Rates

	0.0674	Off-Peak Tariffed Rate
+	0.0025	RTA
=	0.0699	Off-Peak Billed Energy Charges
	0.4144	On-Peak Tariffed Rate
+	0.0025	RTA
=	0.4169	On-Peak Billed Energy Charges

Docket No. E-111/GR-19-478

Exhibit__(DEA-14)
Standby Rate Analysis

Standby Analysis
Cost of Service Summary

Line	Distribution Component			General Service	
1	**Availability**				
2	Meter - Consumer		$	449,082	
3	Acct & Serve - Consumer			993,491	
4	Subtotal			1,442,574	
5	/Customer Months			33,072	
6	Customer Cost ($/Cust/Mo)		**$**	**43.62**	
7					
8	**Primary Service Component**				
9	Substation-Capacity		$	1,598,656	
10	Primary Line - Capacity			3,575,413	
11	Primary Line - Consumer			463,412	
12	Subtotal		$	5,637,481	
13	/Billing Demand kW			1,449,303	
14	Primary Delivery Cost ($/kW/Mo)		**$**	**3.89**	
15					
16	**Secondary Service Component**				
17	Line Transformer Capacity		$	87,871	
18	Line Transformer Consumer			96,436	
19	Sec & Serv. - Consumer			5,512	
20	Subtotal		$	189,819	
21	/Billing Demand kW			1,449,303	
22	Secondary Delivery Cost($/kW/Mo)		**$**	**0.13**	
23	Total		**$**	**4.02**	
24					
25	**Substation Standby Reservation Fee**				
26	Total System Substation Capacity Cost		$	6,109,403	
27	Total Base Rated Substation Capacity	÷		632,500	kVA
28	Subtotal	=	$	9.66	
29	Months	÷		12	
30	Cost per kW-mo	=	**$**	**0.81**	

Docket No. E-111/GR-19-478

Exhibit__(DEA-13)
Air Conditioning Analysis

Dakota Electric Association
Cycled Air Conditioning Credit

Assume:	2.5	Tons AC Capacity
	14.0	Average SEER Rating
	65.0%	Average Peak Diversity Factor
	50.0%	Control Cycle

Cost Analysis (2019 GRE wholesale rates)

	$	18.24	Summer Capacity (per kW month)
+	$	6.57	Transmission (per kW month)
+	$	0.69	Ancillary Service (per kW month)
=	$	25.50	Subtotal
x		3	Summer Months
=	$	76.50	Capacity Savings per Coincident kW
x		0.70	Estimated Coincident Demand Reduction (kW)
=	$	53.28	Power Cost Capacity Savings
+	$	-	Estimated Critical Peak Energy Savings
+	$	15.00	GRE Credit ($5 per unit times 3 months)
=	$	68.28	Estimated Net Power Cost Savings (Summer Season)
-	$	23.38	Control Equipment and Program Costs
-	**$**	**39.00**	**Controlled Credits for Summer Season**
=	$	5.89	Net Annual Revenue

Control Equipment and Program Costs:

	$	116.00	Receiver
+	$	118.00	Electrician and Permit
+	$	17.00	Meter Technician
+	$	(100.00)	GRE Reimbursement
=	$	151.00	Net installed cost of control equipment
x		14.7%	Annualizing Factor *
=	$	22.18	Subtotal
+	$	1.20	Program marketing and Administration **
=	$	23.38	Control Equipment and Program Costs

* Annualizing factor includes interest, depreciation, and O&M.

** Program marketing and administration estimated at 0.1¢ per kWh times typical annual AC consumption of 1,200 kWh.

Docket No. E-111/GR-19-478

Exhibit__(DEA-12)
Base Calculation for Resource &
Tax Adjustment Components

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Energy Cost Adjustment (ECA)

Average Wholesale Energy Cost per kWh		$	0.0521
Rate 70 & 71 Energy Sales			406,800,000
Rate 36 Interruptible Energy Sales			7,801,344
Interruptible Wholesale Energy Cost	=	$	21,600,730
ECA Base per kWh Sold		**$**	**0.0521**

Load Management Rates

Rate 51			
GRE Wholesale Cost - ETS Water Heating		$	0.0200
Rate 51 - ETS Water Heating Sales	x		8,491,977
Rate 51 - ETS Water Heating Power Cost	=	$	169,840
GRE Wholesale Cost - ETS Space Heating		$	0.0225
Rate 51 - ETS Space Heating Sales	x		1,816,023
Rate 51 - ETS Space Heating Power Cost	=	$	40,861
GRE Wholesale Cost - ETS Electric Vehicle		$	0.0200
Rate 51 - ETS Electric Vehicle Sales	x		300,960
Rate 51 - ETS Electric Vehicle Power Cost	=	$	6,019
Rate 51 Power Costs		$	216,720
Rate 51 Energy Sales	÷		10,608,960
Rate 51 Weighted Power Cost Base per kWh Sold	=	**$**	**0.0204**
Rate 52			
GRE Wholesale Cost - Peak Shave Water Heating		$	0.0340
Rate 52 - Peak Shave Water Heating Sales	x		23,557,907
Rate 52 - Peak Shave Water Heating Power Cost	=	$	800,969
GRE Wholesale Cost - Dual Fuel Space Heating		$	0.0365
Rate 52 - Dual Fuel Space Heating Sales	x		20,569,693
Rate 52 - Dual Fuel Space Heating Power Cost	=	$	750,794
Rate 52 Power Costs		$	1,551,763
Rate 52 Energy Sales	÷		44,127,600
Rate 52 Weighted Power Cost Base per kWh Sold	=	**$**	**0.0352**

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Geothermal

Rate 49			
GRE Wholesale Cost - Geothermal		$	0.0813
Rate 49 - Geothermal Energy Sales	x		172,800
Rate 49 - Geothermal Power Cost	=	$	14,049
Rate 49 Power Cost Base per kWh Sold		**$**	**0.0813**

Power Cost Adjustment (PCA)

Total Wholesale Power Cost		$	150,649,466 [A]
ECA Power Cost	-		21,600,730
Rate 51 Power Cost	-		216,720
Rate 52 Power Cost	-		1,551,763
Rate 49 Power Cost	-		14,049
Wellspring (wholesale pass-through)	-		23,370
Member Specific Discount (wholesale pass-through)	-		(45,040)
Large Load High Load Factor Credit (wholesale pass-through)	-		-
Contract Rate Service (wholesale pass-through)	-		-
Standby (wholesale pass-through)	-		27,060
Firm Wholesale Power Cost	=		127,260,814
Firm kWh Energy Sales	÷		1,354,802,496
PCA Power Cost Base per kWh Sold	=	**$**	**0.0939**

Total Wholesale Power Cost		$	150,649,466
Total Energy Sales	÷		1,824,313,200 [B]
Total System Power Cost per kWh Sold	=	**$**	**0.0826**

Notes:

[A] See Exhibit__(DEA-1), page 22 of 22.

[B] See Exhibit__(DEA-1), page 12 of 22.

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Conservation & DSM Spending Base Calculation

2019 Budget Conservation & DSM Spending	$	2,206,789	C
Test Year MWh Sales		1,824,313	
Conservation & DSM Base per kWh	**$**	**0.0012**	

Property Tax Recovery Base Calculation

Test Year Real & Personal Property Taxes	$	3,550,790	D
Test Year MWh Sales		1,824,313	
Property & R/E Tax Recovery Base per kWh	**$**	**0.0019**	

Allocation to Rate Classes Using Cost of Service Method		
Class & Rate	Property & Real Estate Taxes in Base Rates [E]	% of Taxes
Residential & Farm Service 31 Residential 32 Res'l Demand Control 53 Res'l Time of Day	$ 2,223,454	62.62%
Irrigation - 36	25,070	0.71%
Small General Service - 41	116,013	3.27%
General Service - 46 46 - General Service 49 - Geothermal 54 - General Service Time of Day	614,089	17.29%
Interruptible Service - 70 & 71	449,646	12.66%
Lighting - 44, 44-1, 44-2, 44-3	122,518	3.45%
TOTAL	**$ 3,550,790**	100.00%

Notes:

[C] See Workpaper #9

[D] Per Summary of Test Year Adjustments, Exhibit__(DEA_1) Page 2 of 22.

[E] Per Allocation of Revenue Requirements to Rate Classes, Exhibit__(DEA-3). Page 22 of 42.

Docket No. E-111/GR-19-478

Exhibit__(DEA-11)
Line Extension Analysis

Dakota Electric Association
Residential Line Extension Analysis

PROJECT	Direct Labor	Labor Overheads	Contract Labor	Materials, Tools, Supp	Undefined	Total before CIAC	Length (Feet)	Total Cost per Ft before CIAC	Present CIAC Charges	Proposed CIAC Method	Net DEA Cost Above Prop. Recovery Incl. Rates
118039	2,655.61	1,327.82	7,042.05	2,348.02	1,460.59	14,834.09	195	$ 76.07	$ 1,496	$ 3,145	$ 10,407
128798	429.36	214.70	0.00	124.87	236.15	1,005.08	-	NA	$ 500	$ 1,000	$ -
129137	4,054.75	2,487.39	2,062.30	6,594.29	2,230.10	17,428.83	620	$ 28.11	$ 5,024	$ 7,820	$ 8,327
129398	3,456.87	1,728.45	17,769.67	8,834.64	1,901.28	33,690.91	2,153	$ 15.65	$ 10,614	$ 24,683	$ 7,726
130963	1,534.41	767.21	1,512.15	2,378.05	843.93	7,035.75	275	$ 25.58	$ 2,160	$ 4,025	$ 1,729
131747	497.46	248.73	3,876.23	3,899.88	273.60	8,795.90	150	$ 58.64	$ 1,123	$ 2,650	$ 4,864
132939	3,832.37	1,916.21	2,636.92	2,104.75	2,107.81	12,598.06	90	$ 139.98	$ 625	$ 1,990	$ 9,326
133275	1,655.35	987.67	2,891.62	3,280.08	910.45	9,725.17	75	$ 129.67	$ 500	$ 1,825	$ 6,618
133908	2,276.56	1,130.80	2,008.81	2,963.36	1,252.12	9,631.65	442	$ 21.79	$ 3,546	$ 5,862	$ 2,488
134735	2,438.94	1,219.47	0.00	708.47	1,341.42	5,708.30	-	NA	$ 500	$ 1,000	$ 3,426
134795	2,039.50	987.71	9,635.73	4,706.63	1,121.72	18,491.29	209	$ 88.48	$ 1,612	$ 3,299	$ 13,910
134963	1,927.67	720.29	6,230.14	3,285.81	1,060.23	13,224.14	380	$ 34.80	$ 3,032	$ 5,180	$ 6,762
135498	957.98	235.45	1,364.93	2,068.57	526.89	5,153.82	140	$ 36.81	$ 1,040	$ 2,540	$ 1,332
135680	1,239.68	619.86	2,710.17	3,135.59	681.82	8,387.12	475	$ 17.66	$ 3,820	$ 6,225	$ 880
135885	2,207.10	1,103.55	0.00	1,480.77	1,213.91	6,005.33	-	NA	$ 500	$ 1,000	$ 3,723
135973	1,149.39	882.70	0.00	1,609.97	632.16	4,274.22	-	NA	$ 500	$ 1,000	$ 1,992
136252	1,298.65	704.33	1,815.17	2,981.63	714.26	7,514.04	300	$ 25.05	$ 2,368	$ 4,300	$ 1,932
137790	274.42	181.22	0.00	1,415.44	150.92	2,022.00	-	NA	$ 500	$ 1,000	$ -
138306	1,103.55	551.78	0.00	1,338.55	606.95	3,600.83	-	NA	$ 500	$ 1,000	$ 1,319
139509	767.70	383.85	0.00	282.01	422.24	1,855.80	-	NA	$ 213	$ 1,000	$ -
142657	1,454.27	727.17	0.00	1,642.55	799.86	4,623.85	-	NA	$ 500	$ 1,000	$ 2,342
	$ 37,252	$ 19,126	$ 61,556	$ 57,184	$ 20,488	$ 195,606	5,504	30.25	$ 40,670	$ 81,544	$ 89,103
						CIAC as percent of total cost				42%	
						Additional DEA Revenue				$ 40,874	

	$	3,637	Avg Cost for Extensions with No Footage
-	$	1,282	Allocated Dist. Plant - Residential [1]
=	$	2,355	Cost Basis for Flat Fee
	$	**1,000**	**Proposed Flat Fee**
	$	12,809	Avg Cost for Extensions with more than zero feet
-	$	1,282	Allocated Distribution Plant - Residential
-	$	1,000	Proposed Flat Fee
=	$	10,527	Cost Basis for per Foot Charge
		423	Average Footage
	$	24.86	Per Foot Cost Basis
	$	**11.00**	**Proposed per Foot Charge**

Notes:

1 Total residential allocated distribution plant before depreciation.

Class Line Extension Cost Analysis

Line	Description	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1							
2	**I. Class Load Data**						
3	Number of Customers	100,235	4,431	392	2,756	262	16,771
4	Energy (kWh)	838,683,744	42,537,600	7,963,872	463,059,984	406,800,000	10,358,640
5	Billing Demand (kW)	-	-	76,255	1,449,303	970,490	-
6	Base Revenue Per Cons. (Rev - PS)	$ 336	$ 383	$ 1,154	$ 2,584	$ 10,215	$ 76
7							
8	**II. Allocation of Plant**						
9	A. Distribution Extension Items						
10	Poles, towers	$ 11,800,477	$ 612,764	$ 103,966	$ 2,210,293	$ 1,519,012	$ 74,064
11	OH Cond	$ 15,474,059	$ 812,987	$ 106,739	$ 1,411,713	$ 732,940	$ 67,527
12	UG Conduit	$ -	$ -	$ -	$ -	$ -	$ -
13	UG Cond	$ 66,119,564	$ 3,366,400	$ 791,973	$ 22,906,645	$ 17,421,660	$ 624,437
16	Net Plant	$ 93,394,100	$ 4,792,151	$ 1,002,678	$ 26,528,652	$ 19,673,611	$ 766,027
17							
18	Average Plant Invest. / Customer	$ 931.75	$ 1,081.51	$ 2,557.85	$ 9,625.78	$ 75,090.12	$ 45.68
19	Average Plant Invest. / kWh	$ 0.11136	$ 0.11266	$ 0.12590	$ 0.05729	$ 0.04836	$ 0.07395
20	Average Plant Invest. / kW	n/a	n/a	$ 13.15	$ 18.30	$ 20.27	n/a
21	Multiple of Base Revenue	2.8	2.8	2.2	3.7	7.4	0.6
22							
23	B. Service Extension Items						
24	Transf	$ 29,061,904	$ 1,661,843	$ 310,808	$ 2,312,468	$ 761,492	$ 98,727
25	Services	$ 2,401,440	$ 115,874	$ 11,602	$ 80,186	$ 7,918	$ 8,036
26	Meters	$ 3,602,323	$ 218,184	$ 40,621	$ 314,124	$ 138,790	$ 12,055
27	Cons Premise	$ -	$ -	$ -	$ -	$ -	$ 123,745
28	Leased Prop	$ -	$ -	$ -	$ -	$ -	$ -
29	St. Light	$ -	$ -	$ -	$ -	$ -	$ 9,800,721
32	Net Plant	$ 35,065,667	$ 1,995,901	$ 363,031	$ 2,706,778	$ 908,201	##########
33							
34	Average Plant Invest. / Customer	$ 349.83	$ 450.44	$ 926.10	$ 982.14	$ 3,466.41	$ 598.85
35	Average Plant Invest. / kWh	$ 0.04181	$ 0.04692	$ 0.04558	$ 0.00585	$ 0.00223	$ 0.96956
36	Average Plant Invest. / kW	n/a	n/a	$ 4.76	$ 1.87	$ 0.94	n/a
37	Multiple of Base Revenue	1.0	1.2	0.8	0.4	0.3	7.9
38							
39	C. Total Extension Items	$ 1,282	$ 1,532	$ 3,484	$ 10,608	$ 78,557	$ 645

Docket No. E-111/GR-19-478

Exhibit__(DEA-10)
Special Fees and Charges

Dakota Electric Association
Special Fees and Charges
Proposed Fee Changes

	Current Charge	Current Actual Cost	**Proposed Charge**	2018 Frequency	Add'l Revenue
Meter test at customer's request					
Single phase	$ 85.00	$ 98.40	**$ 95.00**	-	$ -
Three phase	$ 100.00	$ 116.34	**$ 110.00**	-	-
Bad check	$ 15.00	$ 11.47	**$ 11.50**	2,259	(7,907)
Reconnection charge (after disconnect, same customer)					
Self contained meter					
Normal working hours	$ 50.00	$ 57.52	**$ 55.00**	741	3,705
After hours	$ 130.00	$ 148.09	**$ 145.00**	28	420
Transformer rated meter					
Normal working hours	$ 175.00	$ 189.77	**$ 185.00**	14	140
After hours	$ 315.00	$ 349.15	**$ 340.00**	1	25
Service charge (outside normal working hours when problem is not with DEA equipment)	$ 280.00	$ 349.15	**$ 340.00**	1	60
Load Management Service Charge					
Normal working hours	$ 70.00	$ 80.46	**$ 80.00**		-
After hours	$ 140.00	$ 161.47	**$ 160.00**	1	20
Pulse meter	$ 500.00	$ 752.26	**$ 750.00**	-	-
Temporary service					
Non-winter months	$ 205.00	N/A	**$ -**	8	(1,640)
Winter months	$ 340.00	N/A	**$ -**	5	(1,700)
Transfer/connection	$ 17.50	$ 19.15	**$ 17.50**	18,760	-
					$ (6,877)

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges

Meter Test at Customer's Request

Single Phase Meter

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Changing Meter:	Labor	Meter Technician		**44.57**	1.00	61.0%	$	71.76
Testing Meter:	Labor	Meter Technician		**44.57**	0.25	61.0%	$	17.94
	Mileage		15	miles	**$ 0.58**	Rate	$	8.70
						Total	$	98.40

Three Phase Meter

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Changing Meter:	Labor	Meter Technician		44.57	1.00	61.0%	$	71.76
Testing Meter:	Labor	Meter Technician		44.57	0.50	61.0%	$	35.88
	Mileage		15	miles	$ 0.58	Rate	$	8.70
						Total	$	116.34

Bad Check or NSF Check

Task	Item	Job Title		Hourly Rate	Minutes	Overhead		Total
Research, Correspondence & Data entry	Labor	Consumer Payment Rep	**$**	**26.80**	5	61.0%	$	3.60
	Bank service charge						**$**	**7.25**
	Correspondence expenses						**$**	**0.62**
						Total	$	11.47

Reconnect Charge

Self Contained Meter - One Person, one vehicle

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Working hours	Labor	Credit Field Rep	**$**	**40.43**	0.75	61.0%	$	48.82
	Mileage		15	miles	$ 0.58	Rate	$	8.70
						Total	$	57.52

Task	Item	Job Title		Overtime rate @ 1.5x	Hours	Payroll Taxes Only		Total
After hours	Labor	Meter Technician	$	60.65	2.00	7.74%	$	130.69
	Mileage		30	miles	$ 0.58	Rate	$	17.40
						Total	$	148.09

Transformer Rated Meter - Two person crew, one truck

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Working hours	Labor	Crew Chief	**$**	**51.70**	1.00	61.0%	$	83.24
	Labor	Power Line Specialist	**$**	**46.55**	1.00	61.0%	$	74.95
	Bucket Truck		**$**	**31.58**	1.00		$	31.58
						Total	$	189.77

Task	Item	Job Title		Overtime rate @ 1.5x	Hours	Payroll Taxes Only		Total
After hours	Labor	Crew Chief	$	77.55	2.00	7.74%	$	167.10
	Labor	Power Line Specialist	$	69.83	2.00	7.74%	$	150.47
	Bucket Truck		$	31.58	1.00		$	31.58
						Total	$	349.15

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges
(Continued)

Service Charge - two person crew, one truck
(service trouble calls after working hours, when the problem is not with DEA's equipment)

Task	Item	Job Title		Overtime rate @ 1.5x	Hours	Payroll Taxes Only	Total
After hours	Labor	Crew Chief	$	77.55	2.00	7.74%	$ 167.10
	Labor	Power Line Specialist	$	69.83	2.00	7.74%	$ 150.47
	Bucket Truck		$	31.58	1.00		$ 31.58
						Total	$ 349.15

Load Management Service Charge

Task	Item	Job Title			Hours		Total
Working Hours							
Testing	Labor	Meter Technician		44.57	1.00	61.0%	$ 71.76
	Mileage		15	miles	$ 0.58	Rate	$ 8.70
						Total	$ 80.46
After hours	Labor	Meter Technician	$	66.86	2.00	7.74%	$ 144.07
	Mileage		30	miles	$ 0.58	Rate	$ 17.40
						Total	$ 161.47

Pulse Meter (materials and installation)

Task	Item	Job Title		Hourly Rate	Hours	Overhead	Total
Installation	Labor	Meter Technician	$	44.57	2.00	61.0%	$ 143.52
	Labor	Meter Technician	$	44.57	2.00	61.0%	$ 143.52
	Equipment	Meter					**$ 285.00**
	Equipment	KYZ pulse board					**$ 70.00**
	Labor	install & test board	$	44.57	0.75	61.0%	$ 53.82
	Equipment	test switch					**$ 170.22**
	Equipment	Miscellaneous equipment					**$ 10.00**
						Total	$ 752.26

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges
(Continued)

Transfer/Connection Charge Analysis

Task	Employees	Job Title		Hourly Rate	(% of 2080) Hours	Overhead		Total
Inside Clerical								
Telephone & resolution	12	Member Service Reps	$	26.80	8.8%	61.0%	$	94,773.72
Supervision	2	MSR Leads	**$**	**31.20**	1.5%	61.0%	$	3,134.48
Outside Field Personnel								
	1	Transfer representative	**$**	**36.47**	70%	61.0%	$	85,491.52
	1	Chief meter reader	$	36.47	39%	61.0%	$	47,630.99
	1	Meter reader	$	36.47	65%	61.0%	$	79,384.98
Vehicle Expense	Mileage	Transfer representative		**25,400**	70.00%	17,780		
		Chief meter reader		**17,700**	39.00%	6,903		
		Meter reader		**16,600**	65.00%	10,790		
					Subtotal	35,473		
		Mileage Rate	$	0.58			$	20,574.34
Data Processing								
Itineris Support		Monthly Support	**$**	**18,180.00**	10.00%		$	21,816.00
PC & 2 monitors	12	Annual cost	**$**	**430.00**	8.80%		$	454.00
			Number					
Mailing	Kubra cost per item including postage				**$ 0.63**			
			Subtotal		$ 0.63	**9,380**	$	5,909.40

Total	$	359,169.43
Transfers		18,760
$/Transfer	$	19.15

Dakota Electric Association
Special Fees and Charges
Frequency Analysis

	2013	2018
Meter test at customer's request		
Single phase	4	-
Three phase	-	
Bad check	1,476	2,259
Reconnection charge (after disconnect, same customer)		
Self contained meter		
Normal working hours	1,241	741
After hours	131	28
Transformer rated meter		
Normal working hours	6	14
After hours	2	1
Service charge	1	1
(outside normal working hours		
when problem is not with DEA equipment)		
Pulse meter	-	
Temporary service	34	13
Transfer/connection	13,722	18,760

Dakota Electric Association
Special Fees and Charges
Payroll Overhead Calculation

	Future Test Year	
Pension	16.71%	[1]
Savings (401k)	6.77%	[1]
FICA Tax [2]	7.60%	[1]
Life Insurance	0.60%	[1]
Workers' Compensation	1.32%	[1]
Medical Insurance	12.87%	[1]
State & Federal Unemployment	0.14%	[1]
Other-Retirement Health Benefits	0.93%	[1]
Benefits excluding time-off	46.94%	
Vacation/Sick/Holiday (assumed 269 hrs)	14.04%	
Total overhead allocation	60.98%	
Payroll taxes only	7.74%	

[1] See Exhibit__(DEA-1), page 6 of 20.

Docket No. E-111/GR-19-478

Exhibit__(DEA-9)
Summary of Lead-Lag Study

Dakota Electric Association
Summary of Lead Lag Analysis
Cash Working Capital Analysis
Twelve Months Ending December 31, 2018

Description	Test Year Expense	365 Average Daily Expense	Expense Lag	Revenue Lag		Net Lag/ (Lead)	Working Capital Required/ (Provided)
Purchased Power	$ 149,356,821	$ 409,197	51.7	55.1		3.4	$ 1,399,996
Payroll (A)	15,112,543	41,404	11.0	55.1		44.1	1,826,799
Employee Benefits	6,003,178	16,447	(37.5)	55.1		92.6	1,523,343
Other O&M	9,484,952	25,986	18.3	55.1		36.8	956,839
Prepaid Insurance	570,291	1,562	(180.6)	55.1		235.7	368,197
Employer FICA/Medicare	1,334,808	3,657	14.4	55.1		40.7	148,918
Federal & State Unemployment Tax	26,186	72	60.0	55.1		(4.9)	(351)
Property Taxes	3,432,442	9,404	(30.5)	55.1		85.6	805,183
Total Expenses	$ 185,321,221						$ 7,028,924
Sales Tax	$ 11,767,404	32,239	34.9	28.3	(B)	(6.6)	$ (212,777)
Working Capital Required/ (Provided)							$ 6,816,147

(A) Operating payroll is estimated to be 86% of total payroll
(B) Revenue Collection or Customer Payment Lag

Docket No. E-111/GR-19-478

Exhibit__(DEA-8)
Coincidental Demand Charges

Dakota Electric Association
Calculation of Coincidental Demand Charges

C&I Interruptible (Rates 70 and 71)

1. Summer (June, July, August)

	$ 25.50	GRE Summer $/kW-mo.
+	2.50%	DEA Line Loss
	$26.14	Coincidental Demand Charge

2. Winter (January, February, December)

	$ 19.42	GRE Winter $/kW-mo.
+	2.50%	DEA Line Loss
	$19.91	Coincidental Demand Charge

3. Other Months

	$ 13.34	GRE Winter $/kW-mo.
+	2.50%	DEA Line Loss
	$13.67	Coincidental Demand Charge

Note: GRE wholesale rates include capacity, transmission, and ancillary service charges.

Docket No. E-111/GR-19-478

Exhibit__(DEA-7)
Monthly Fixed Charge Analysis

Monthly Fixed Charge Analysis
Residential Service (Schedule 31)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 1.89		
Interest	$ 0.63		
O&M	$ 3.49		
A&G	$ 1.68		
Subtotal		$ 7.70	
Transformer			
Depreciation	$ 0.68		
Interest	$ 0.23		
O&M	$ 0.03		
A&G	$ 0.01		
Subtotal		$ 0.96	$ 0.96
Meter & Service			
Depreciation	$ 0.18		
Interest	$ 0.06		
O&M	$ 2.66		
A&G	$ 1.28		
Subtotal		$ 4.19	$ 4.19
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 9.34		$ 9.34
Taxes & Miscellaneous	$ 1.21		$ 0.15
Margins	$ 1.72		$ 0.38
Subtotal		$ 12.27	
Total		$ 25.11	$ 15.01

Monthly Fixed Charge Analysis
Small General Service (Schedule 41)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	$/cons./mo.	Excluding Primary Line $/cons./mo.
Primary Line			
Depreciation	$ 2.26		
Interest	$ 0.76		
O&M	$ 4.17		
A&G	$ 2.01		
Subtotal		$ 9.21	
Transformer			
Depreciation	$ 0.92		
Interest	$ 0.31		
O&M	$ 0.04		
A&G	$ 0.02		
Subtotal		$ 1.28	$ 1.28
Meter & Service			
Depreciation	$ 0.23		
Interest	$ 0.08		
O&M	$ 3.64		
A&G	$ 1.76		
Subtotal		$ 5.71	$ 5.71
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 12.79		$ 12.79
Taxes & Miscellaneous	$ 1.52		$ 0.15
Margins	$ 2.13		$ 0.38
Subtotal		$ 16.44	
Total		$ 32.65	$ 20.32

Monthly Fixed Charge Analysis
Irrigation Service (Schedule 36)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 2.85		
Interest	$ 0.95		
O&M	$ 5.25		
A&G	$ 2.53		
Subtotal		$ 11.58	
Transformer			
Depreciation	$ 1.29		
Interest	$ 0.43		
O&M	$ 0.06		
A&G	$ 0.02		
Subtotal		$ 1.80	$ 1.80
Meter & Service			
Depreciation	$ 0.43		
Interest	$ 0.14		
O&M	$ 7.67		
A&G	$ 3.70		
Subtotal		$ 11.94	$ 11.94
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 26.92		$ 26.92
Taxes & Miscellaneous	$ 2.22		$ 0.15
Margins	$ 2.85		$ 0.38
Subtotal		$ 31.99	
Total		$ 57.31	$ 41.19

Monthly Fixed Charge Analysis
General Service (Schedule 46)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 2.76		
Interest	$ 0.93		
O&M	$ 5.09		
A&G	$ 2.46		
Subtotal		$ 11.24	
Transformer			
Depreciation	$ 1.23		
Interest	$ 0.41		
O&M	$ 0.05		
A&G	$ 0.02		
Subtotal		$ 1.72	$ 1.72
Meter & Service			
Depreciation	$ 0.46		
Interest	$ 0.15		
O&M	$ 8.44		
A&G	$ 4.07		
Subtotal		$ 13.12	$ 13.12
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 29.61		$ 29.61
Taxes & Miscellaneous	$ 2.23		$ 0.15
Margins	$ 2.78		$ 0.38
Subtotal		$ 34.63	
Total		$ 60.71	$ 44.99

Monthly Fixed Charge Analysis
C&I Interruptible Service (Schedules 70 & 71)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	$/cons./mo.	Excluding Primary Line $/cons./mo.
Primary Line			
Depreciation	$ 2.95		
Interest	$ 0.99		
O&M	$ 5.44		
A&G	$ 2.63		
Subtotal		$ 12.01	
Transformer			
Depreciation	$ 1.35		
Interest	$ 0.45		
O&M	$ 0.06		
A&G	$ 0.02		
Subtotal		$ 1.89	$ 1.89
Meter & Service			
Depreciation	$ 1.88		
Interest	$ 0.63		
O&M	$ 39.21		
A&G	$ 18.91		
Subtotal		$ 60.63	$ 60.63
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 137.64		$ 137.64
Taxes & Miscellaneous	$ 5.04		$ 0.15
Margins	$ 3.86		$ 0.38
Subtotal		$ 146.54	
Total		$ 221.08	$ 200.69

Docket No. E-111/GR-19-478

Exhibit__(DEA-6)
Comparison of Present and Proposed Rates

Comparison of
Present and Proposed Rate Schedules

Present Rates				Proposed Rates			
Residential & Farm Service (31)				**Residential & Farm Service (31)**			
Fixed Charge	@	$9.00	/month	Fixed Charge	@	$10.00	/month
Energy Charge				Energy Charge			
Summer	@	$0.13080	/kWh	Summer	@	$0.13790	/kWh
Other	@	$0.11680	/kWh	Other	@	$0.12390	/kWh
Residential & Farm Demand Control (32)				**Residential & Farm Demand Control (32)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Demand Charge				Demand Charge			
Summer	@	$14.70	/kW	Summer	@	$15.50	/kW
Other	@	$11.10	/kW	Other	@	$11.90	/kW
Energy Charge	@	$0.07600	/kWh	Energy Charge	@	$0.08100	/kWh
Electric Vehicle (33)				**Electric Vehicle (33)**			
Energy Charge				Energy Charge			
Off Peak	@	$0.06740	/kWh	Off Peak	@	$0.07560	/kWh
On Peak	@	$0.41440	/kWh	On Peak	@	$0.44210	/kWh
Other				Other			
Summer	@	$0.13080	/kWh	Summer	@	$0.13790	/kWh
Other	@	$0.11680	/kWh	Other	@	$0.12390	/kWh
Irrigation Service (36)				**Irrigation Service (36)**			
Firm Service				***Firm Service***			
Fixed Charge	@	$30.00	/month	Fixed Charge	@	$30.00	/month
Demand Charge				Demand Charge			/kW/mo.
Summer	@	$26.35	/kW/mo.	Summer	@	$26.60	/kW/mo.
Winter	@	$20.95	/kW/mo.	Winter	@	$21.20	
Other	@	$15.50	/kW/mo.	Other	@	$15.67	/kW/mo.
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Interruptible Service				***Interruptible Service***			
Fixed Charge	@	$30.00	/month	Fixed Charge	@	$30.00	/month
Demand Charge	@	$4.55	/kW/mo.	Demand Charge	@	$4.55	/kW/mo.
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Small General Service (41)				**Small General Service (41)**			
Fixed Charge	@	$14.00	/month	Fixed Charge	@	$15.00	/month
Energy Charge				Energy Charge			
Summer	@	$0.12690	/kWh	Summer	@	$0.13750	/kWh
Other	@	$0.11290	/kWh	Other	@	$0.12350	/kWh

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Security Lighting Service (44) - Closed to New				**Security Lighting Service (44) - Closed to New**			
175 W MV	@	N/A	/month	175 W MV	@	N/A	/month
100 W HPS	@	$10.10	/month	100 W HPS	@	$12.01	/month
150 W HPS	@	$11.99	/month	150 W HPS	@	$14.26	/month
250 W HPS	@	$15.79	/month	250 W HPS	@	$18.83	/month
Street Lighting System (44-1)				**Street Lighting System (44-1)**			
175 W MV (Clsd to New)	@	$10.52	/month	175 W MV (Clsd to New)	@	$13.25	/month
250 W MV (Clsd to New)	@	$13.46	/month	250 W MV (Clsd to New)	@	$16.74	/month
400 W MV (Clsd to New)	@	$18.54	/month	400 W MV (Clsd to New)	@	$22.71	/month
100 W HPS (Clse to New)	@	$7.56	/month	100 W HPS (Clse to New)	@	$9.61	/month
150 W HPS	@	$9.46	/month	150 W HPS	@	$11.78	/month
200 W HPS	@	$11.41	/month	200 W HPS	@	$14.18	/month
250 W HPS	@	$13.25	/month	250 W HPS	@	$16.35	/month
400 W HPS	@	$17.67	/month	400 W HPS	@	$21.24	/month
Street Lighting Service (44-2)				**Street Lighting Service (44-2)**			
175 W MV (Clsd to New)	@	$15.23	/month	175 W MV (Clsd to New)	@	$17.44	/month
250 W MV (Clsd to New)	@	$18.16	/month	250 W MV (Clsd to New)	@	$20.93	/month
400 W MV (Clsd to New)	@	$23.25	/month	400 W MV (Clsd to New)	@	$26.89	/month
100 W HPS (Clsd to New)	@	$12.27	/month	100 W HPS (Clsd to New)	@	$13.80	/month
150 W HPS (Clsd to New)	@	$14.16	/month	150 W HPS (Clsd to New)	@	$15.97	/month
250 W HPS (Clsd to New)	@	$17.95	/month	250 W HPS (Clsd to New)	@	$20.54	/month
400 W HPS (Clsd to New)	@	$22.38	/month	400 W HPS (Clsd to New)	@	$25.42	/month
Custom Residential Street Lighting (44-3)				**Custom Residential Street Lighting (44-3)**			
175 W MV (Clsd to New)	@	$11.37	/month	175 W MV (Clsd to New)	@	$14.03	/month
50 W HPS (Clsd to New)	@	$6.70	/month	50 W HPS (Clsd to New)	@	$8.45	/month
100 W HPS	@	$8.41	/month	100 W HPS	@	$10.39	/month
150 W HPS (Clsd to New)	@	$10.30	/month	150 W HPS (Clsd to New)	@	$12.63	/month
250 W HPS (Clsd to New)	@	$14.09	/month	250 W HPS (Clsd to New)	@	$17.21	/month
LED Security Lighting Service (44 -4)				**LED Security Lighting Service (44 -4)**			
LED, >4,500 Lumens	@	7.63	/month	LED, >4,500 Lumens	@	$7.75	/month

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
LED Street Lighting Member Owned(44-5)				**LED Street Lighting Member Owned(44-5)**			
A (40-80 watts)	@	4.81	/month	A (40-80 watts)	@	$5.50	/month
B (81-150 watts)	@	$6.71	/month	B (81-150 watts)	@	$7.75	/month
C (151-250 watts)	@	$9.66	/month	C (151-250 watts)	@	$11.16	/month
D (251-350 watts)	@	$13.05	/month	D (251-350 watts)	@	$15.04	/month
E (351-450 watts)	@	$16.52	/month	E (351-450 watts)		$19.07	/month
LED Street Lighting (44-6)				**LED Street Lighting (44-6)**			
Standard							
>5,200 L, Coach (Post)	@	$10.60	/month	>5,200 L, Coach (Post)	@	$9.30	/month
>5,200 L, Acorn (Post)	@	$11.24	/month	>5,200 L, Acorn (Post)	@	$10.85	/month
>7,000 L, Cobra (Mast)	@	$8.31	/month	>7,000 L, Cobra (Mast)	@	$8.60	/month
>11,500 L, Shoebox	@	$10.71	/month	>11,500 L, Shoebox	@	$10.70	/month
Basic							
>5,200 L, Coach (Post)	@	$6.83	/month	>5,200 L, Coach (Post)	@	$6.36	/month
>5,200 L, Acorn (Post)	@	$6.30	/month	>5,200 L, Acorn (Post)	@	$6.12	/month
>7,000 L, Cobra (Mast)	@	$6.51	/month	>7,000 L, Cobra (Mast)	@	$6.98	/month
>11,500 L, Shoebox	@	$7.98	/month	>11,500 L, Shoebox	@	$8.68	/month
Low Wattage Unmetered Service (45)				**Low Wattage Unmetered Service (45)**			
Fixed Charge	@	$10.00	/month	Fixed Charge	@	$10.50	/month
General Service (46)				**General Service (46)**			
Fixed Charge	@	$34.00	/month	Fixed Charge	@	$34.00	/month
Demand Charge				Demand Charge			
Summer	@	$12.26	/kW	Summer	@	$13.70	/kW
Other	@	$9.16	/kW	Other	@	$10.60	/kW
Energy Charge				Energy Charge			
First 200 kWh/kW	@	$0.07760	/kWh	First 200 kWh/kW	@	$0.07760	/kWh
Next 200 kWh/kW	@	$0.06760	/kWh	Next 200 kWh/kW	@	$0.06760	/kWh
Over 400 kWh/kW	@	$0.05760	/kWh	Over 400 kWh/kW	@	$0.05760	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Municipal Civil Defense Sirens (47)				**Municipal Civil Defense Sirens (47)**			
Fixed Charge	@	$5.00	/month	Fixed Charge	@	$5.00	/month
Geothermal Heat Pump (49) Closed to New				**Geothermal Heat Pump (49) Closed to New**			
Energy Charge	@	$0.09400	/kWh	Energy Charge	@	$0.10300	/kWh
Controlled Energy Storage (51)				**Controlled Energy Storage (51)**			
Net Energy Charge	@	$0.04400	/kWh	Net Energy Charge	@	$0.04870	/kWh
Controlled Interruptible Service (52)				**Controlled Interruptible Service (52)**			
Net Energy Charge	@	$0.05500	/kWh	Net Energy Charge	@	$0.06310	/kWh
Alternate Rate for Water				Alternate Rate for Water			
Heaters		($6.00)	/month	Heaters		($6.00)	/month
Residential & Farm Time of Day (53)				**Residential & Farm Time of Day (53)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Energy Charge				Energy Charge			
Peak Period				Peak Period			
Summer	@	$0.18800	/kWh	Summer	@	$0.21263	/kWh
Other	@	$0.17400	/kWh	Other	@	$0.19863	/kWh
Off-Peak	@	$0.09400	/kWh	Off-Peak	@	$0.09450	/kWh
General Service Time of Day (54)				**General Service Time of Day (54)**			
Fixed Charge	@	$36.00	/month	Fixed Charge	@	$36.00	/month
Demand Charge				Demand Charge			
Peak Period				Peak Period			
Summer	@	$24.85	/kW/mo.	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW/mo.	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW/mo.	Other	@	$13.67	/kW/mo.
Maximum	@	$4.75	/kW	Maximum	@	$5.25	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Residential & Farm Service Time of Day (56)				**Residential & Farm Service Time of Day (56)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Energy Charges				Energy Charges			
Peak Period				Peak Period			
Summer	@	$0.2710	/kWh	Summer	@	$0.2890	/kW/mo.
Winter	@	$0.2210	/kWh	Winter	@	$0.2320	/kW/mo.
Other	@	$0.1750	/kWh	Other	@	$0.1880	/kW/mo.
Intermediate Period	@	$0.0970	/kWh	Intermediate Period	@	$0.1060	/kWh
Off-Peak Period	@	$0.0760	/kWh	Off-Peak Period	@	$0.0820	/kWh
Standby Service (60)				**Standby Service (60)**			
Generation Reservation Fee				Generation Reservation Fee			
Summer	@	$3.21	/kW	Summer	@	$3.21	/kW
Winter	@	$2.47	/kW	Winter	@	$2.47	/kW
Other	@	$1.74	/kW	Other	@	$1.74	/kW
Distribution Reservation Fee				Distribution Reservation Fee			
Primary	@	$3.28	/kW	Primary	@	$3.89	/kW
Secondary	@	$3.51	/kW	Secondary	@	$4.02	/kW
Substation	@	$0.90	/kW	Substation	@	$0.81	/kW
Full Interruptible Service (70)				**Full Interruptible Service (70)**			
Fixed Charge	@	$110.00	/month	Fixed Charge	@	$130.00	/month
Communication Fee	@	$8.70	/month	Communication Fee	@	$8.70	/month
Coinc. Demand Charge				Coinc. Demand Charge			
Summer	@	$24.85	/kW	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW	Other	@	$13.67	/kW/mo.
Non-Coinc. Demand	@	$4.75	/kW	Non-Coinc. Demand	@	$5.25	/kW
Failure to Control		$5.00	/kW	Failure to Control	@	$5.00	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	
Partial Interruptible Service (71)				**Partial Interruptible Service (71)**			
Fixed Charge	@	$110.00	/month	Fixed Charge	@	$130.00	/month
Communication Fee	@	$8.70	/month	Communication Fee	@	$8.70	/month
Coinc. Demand Charge				Coinc. Demand Charge			
Summer	@	$24.85	/kW	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW	Other	@	$13.67	/kW/mo.
Non-Coinc. Demand	@	$4.75	/kW	Non-Coinc. Demand	@	$5.25	/kW
Excess Demand	@	$5.00	/kW	Excess Demand	@	$5.00	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				**Proposed Rates**			
Cycled Air Conditioning Service (80)				**Cycled Air Conditioning Service (80)**			
Option 1	@		/kWh	Option 1	@		/kWh
Option 2	@	($0.03200)	/kWh	Option 2	@	($0.03200)	/kWh
Option 3	@	($13.00)	/month	Option 3	@	($13.00)	/month
Option 4	@	($6.50)	/ton/mo.	Option 4	@	($6.50)	/ton/mo.

Comparison of Revenue
Present and Proposed Rates

(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44) - Closed to New	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44 -4)	31,109	31,434	325	1.04
12	LED Street Lighting Member Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49) Closed to New	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	1	(0.00)
26	Wellspring	23,370	23,370	-	-
27	**Total**	200,480,307	209,128,484	8,648,177	4.31

Comparison of Present and Proposed
Residential & Farm Service (31)

Present			**Proposed**		
Service Charge	$9.00	/mo.	Fixed Charge	$10.00	/mo.
Energy Charge			Energy Charge		
Summer	$0.13080	kWh	Summer	$0.13790	kWh
Other	$0.11680	kWh	Other	$0.12390	kWh
RTA Charge	$0.00250	kWh			

kWh/	Present		Proposed Billing		Present vs. Proposed				Average Rate			
					Summer		Other		Present		Proposed	
Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
100	22.33	20.93	23.79	22.39	1.46	6.54	1.46	6.98	22.33	20.93	23.79	22.39
200	35.66	32.86	37.58	34.78	1.92	5.38	1.92	5.84	17.83	16.43	18.79	17.39
300	48.99	44.79	51.37	47.17	2.38	4.86	2.38	5.31	16.33	14.93	17.12	15.72
400	62.32	56.72	65.16	59.56	2.84	4.56	2.84	5.01	15.58	14.18	16.29	14.89
500	75.65	68.65	78.95	71.95	3.30	4.36	3.30	4.81	15.13	13.73	15.79	14.39
600	88.98	80.58	92.74	84.34	3.76	4.23	3.76	4.67	14.83	13.43	15.46	14.06
700	102.31	92.51	106.53	96.73	4.22	4.12	4.22	4.56	14.62	13.22	15.22	13.82
800	115.64	104.44	120.32	109.12	4.68	4.05	4.68	4.48	14.46	13.06	15.04	13.64
900	128.97	116.37	134.11	121.51	5.14	3.99	5.14	4.42	14.33	12.93	14.90	13.50
1,000	142.30	128.30	147.90	133.90	5.60	3.94	5.60	4.36	14.23	12.83	14.79	13.39
1,100	155.63	140.23	161.69	146.29	6.06	3.89	6.06	4.32	14.15	12.75	14.70	13.30
1,200	168.96	152.16	175.48	158.68	6.52	3.86	6.52	4.28	14.08	12.68	14.62	13.22
1,300	182.29	164.09	189.27	171.07	6.98	3.83	6.98	4.25	14.02	12.62	14.56	13.16
1,400	195.62	176.02	203.06	183.46	7.44	3.80	7.44	4.23	13.97	12.57	14.50	13.10
1,500	208.95	187.95	216.85	195.85	7.90	3.78	7.90	4.20	13.93	12.53	14.46	13.06
1,600	222.28	199.88	230.64	208.24	8.36	3.76	8.36	4.18	13.89	12.49	14.42	13.02
1,700	235.61	211.81	244.43	220.63	8.82	3.74	8.82	4.16	13.86	12.46	14.38	12.98
1,800	248.94	223.74	258.22	233.02	9.28	3.73	9.28	4.15	13.83	12.43	14.35	12.95
1,900	262.27	235.67	272.01	245.41	9.74	3.71	9.74	4.13	13.80	12.40	14.32	12.92
2,000	275.60	247.60	285.80	257.80	10.20	3.70	10.20	4.12	13.78	12.38	14.29	12.89

Comparison of Present and Proposed
Small General Service (41)

Present			**Proposed**		
Service Charge	$14.00	/mo.	Fixed Charge	$15.00	/mo.
Energy Charge			Energy Charge		
Summer	$0.12690	kWh	Summer	$0.13750	kWh
Other	$0.11290	kWh	Other	$0.12350	kWh
RTA Charge	$0.00250	kWh			

					Present vs. Proposed				Average Rate			
kWh/	Present		Proposed Billing		Summer		Other		Present		Proposed	
Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
100	26.94	25.54	28.75	27.35	1.81	6.72	1.81	6.72	26.94	25.54	28.75	27.35
200	39.88	37.08	42.50	39.70	2.62	6.57	2.62	6.57	19.94	18.54	21.25	19.85
300	52.82	48.62	56.25	52.05	3.43	6.49	3.43	6.49	17.61	16.21	18.75	17.35
400	65.76	60.16	70.00	64.40	4.24	6.45	4.24	6.45	16.44	15.04	17.50	16.10
500	78.70	71.70	83.75	76.75	5.05	6.42	5.05	6.42	15.74	14.34	16.75	15.35
600	91.64	83.24	97.50	89.10	5.86	6.39	5.86	6.39	15.27	13.87	16.25	14.85
700	104.58	94.78	111.25	101.45	6.67	6.38	6.67	6.38	14.94	13.54	15.89	14.49
800	117.52	106.32	125.00	113.80	7.48	6.36	7.48	6.36	14.69	13.29	15.63	14.23
900	130.46	117.86	138.75	126.15	8.29	6.35	8.29	6.35	14.50	13.10	15.42	14.02
1,000	143.40	129.40	152.50	138.50	9.10	6.35	9.10	6.35	14.34	12.94	15.25	13.85
1,100	156.34	140.94	166.25	150.85	9.91	6.34	9.91	6.34	14.21	12.81	15.11	13.71
1,200	169.28	152.48	180.00	163.20	10.72	6.33	10.72	6.33	14.11	12.71	15.00	13.60
1,300	182.22	164.02	193.75	175.55	11.53	6.33	11.53	6.33	14.02	12.62	14.90	13.50
1,400	195.16	175.56	207.50	187.90	12.34	6.32	12.34	6.32	13.94	12.54	14.82	13.42
1,500	208.10	187.10	221.25	200.25	13.15	6.32	13.15	6.32	13.87	12.47	14.75	13.35
2,000	272.80	244.80	290.00	262.00	17.20	6.30	17.20	6.30	13.64	12.24	14.50	13.10
2,500	337.50	302.50	358.75	323.75	21.25	6.30	21.25	6.30	13.50	12.10	14.35	12.95
3,000	402.20	360.20	427.50	385.50	25.30	6.29	25.30	6.29	13.41	12.01	14.25	12.85
3,500	466.90	417.90	496.25	447.25	29.35	6.29	29.35	6.29	13.34	11.94	14.18	12.78
4,000	531.60	475.60	565.00	509.00	33.40	6.28	33.40	6.28	13.29	11.89	14.13	12.73

Comparison of Present and Proposed
General Service (46)
Based on 40 kW

Present			**Proposed**		
Fixed Charge	$34.00	/mo.	Fixed Charge	$34.00	/mo.
Demand Charge			Demand Charge		
Summer	$12.26	/kW	Summer	$13.70	/kW
Other	$9.16	/kW	Other	$10.60	/kW
Energy Charge			Energy Charge		
First 200 kWh/kW	$0.07760	/kWh	First 200 kWh/k\	$0.07760	/kWh
Next 200 kWh/kW	$0.06760	/kWh	Next 200 kWh/k\	$0.06760	/kWh
Over 400 kWh/kW	$0.05760	/kWh	Over 400 kWh/k\	$0.05760	/kWh
RTA Charge	$0.0025	/kWh			

Avg		Billing				Present vs. Proposed				Average Rate			
Load	kWh/	Present		Proposed		Summer		Other		Present		Proposed	
Factor	**Mo.**	**Summer**	**Other**	**Summer**	**Other**	**Incr./(Decr.)**		**Incr./(Decr.)**		**Summer**	**Other**	**Summer**	**Other**
(%)	(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
-	-	524.40	400.40	582.00	458.00	57.60	10.98	57.60	14.39	N.A.	N.A.	N.A.	N.A.
5	1,460	641.35	517.35	695.30	571.30	53.95	8.41	53.95	10.43	43.93	35.43	47.62	39.13
10	2,920	758.29	634.29	808.59	684.59	50.30	6.63	50.30	7.93	25.97	21.72	27.69	23.44
15	4,380	875.24	751.24	921.89	797.89	46.65	5.33	46.65	6.21	19.98	17.15	21.05	18.22
20	5,840	992.18	868.18	1,035.18	911.18	43.00	4.33	43.00	4.95	16.99	14.87	17.73	15.60
25	7,300	1,109.13	985.13	1,148.48	1,024.48	39.35	3.55	39.35	3.99	15.19	13.49	15.73	14.03
30	8,760	1,218.48	1,094.48	1,254.18	1,130.18	35.70	2.93	35.70	3.26	13.91	12.49	14.32	12.90
35	10,220	1,320.82	1,196.82	1,352.87	1,228.87	32.05	2.43	32.05	2.68	12.92	11.71	13.24	12.02
40	11,680	1,423.17	1,299.17	1,451.57	1,327.57	28.40	2.00	28.40	2.19	12.18	11.12	12.43	11.37
45	13,140	1,525.51	1,401.51	1,550.26	1,426.26	24.75	1.62	24.75	1.77	11.61	10.67	11.80	10.85
50	14,600	1,627.86	1,503.86	1,648.96	1,524.96	21.10	1.30	21.10	1.40	11.15	10.30	11.29	10.44
55	16,060	1,729.61	1,605.61	1,747.06	1,623.06	17.45	1.01	17.45	1.09	10.77	10.00	10.88	10.11
60	17,520	1,817.35	1,693.35	1,831.15	1,707.15	13.80	0.76	13.80	0.81	10.37	9.67	10.45	9.74
65	18,980	1,905.10	1,781.10	1,915.25	1,791.25	10.15	0.53	10.15	0.57	10.04	9.38	10.09	9.44
70	20,440	1,992.84	1,868.84	1,999.34	1,875.34	6.50	0.33	6.50	0.35	9.75	9.14	9.78	9.17
75	21,900	2,080.59	1,956.59	2,083.44	1,959.44	2.85	0.14	2.85	0.15	9.50	8.93	9.51	8.95
80	23,360	2,168.34	2,044.34	2,167.54	2,043.54	(0.80)	(0.04)	(0.80)	(0.04)	9.28	8.75	9.28	8.75
85	24,820	2,256.08	2,132.08	2,251.63	2,127.63	(4.45)	(0.20)	(4.45)	(0.21)	9.09	8.59	9.07	8.5[illegible]
90	26,280	2,343.83	2,219.83	2,335.73	2,211.73	(8.10)	(0.35)	(8.10)	(0.36)	8.92	8.45	8.89	8.4[illegible]
95	27,740	2,431.57	2,307.57	2,419.82	2,295.82	(11.75)	(0.48)	(11.75)	(0.51)	8.77	8.32	8.72	8.2[illegible]
100	29,200	2,519.32	2,395.32	2,503.92	2,379.92	(15.40)	(0.61)	(15.40)	(0.64)	8.63	8.20	8.58	8.15

Comparison of Present and Proposed
General Service (46)
Based on 230 kW

Present			**Proposed**		
Fixed Charge	$34.00	/mo.	Fixed Charge	$34.00	/mo.
Demand Charge			Demand Charge		
Summer	$12.26	/kW	Summer	$13.70	/kW
Other	$9.16	/kW	Other	$10.60	/kW
Energy Charge			Energy Charge		/kWh
First 200 kWh/kW	$0.07760	/kWh	First 200 kWh/kV	$0.07760	
Next 200 kWh/kW	$0.06760	/kWh	Next 200 kWh/k'	$0.06760	
Over 400 kWh/kW	$0.05760	/kWh	Over 400 kWh/k'	$0.05760	
RTA Charge	$0.00250	/kWh			

Avg. Load Factor	kWh/ Mo.	Billing Present Summer	Billing Present Other	Billing Proposed Summer	Billing Proposed Other	Present vs. Proposed Summer Incr./(Decr.)		Present vs. Proposed Other Incr./(Decr.)		Average Rate Present Summer	Average Rate Present Other	Average Rate Proposed Summer	Average Rate Proposed Other
(%)	(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
-	-	2,853.80	2,140.80	3,185.00	2,472.00	331.20	11.61	331.20	15.47	N.A.	N.A.	N.A.	N.A.
5	8,395	3,526.24	2,813.24	3,836.45	3,123.45	310.21	8.80	310.21	11.03	42.00	33.51	45.70	37.21
10	16,790	4,198.68	3,485.68	4,487.90	3,774.90	289.22	6.89	289.22	8.30	25.01	20.76	26.73	22.48
15	25,185	4,871.12	4,158.12	5,139.36	4,426.36	268.24	5.51	268.24	6.45	19.34	16.51	20.41	17.58
20	33,580	5,543.56	4,830.56	5,790.81	5,077.81	247.25	4.46	247.25	5.12	16.51	14.39	17.24	15.12
25	41,975	6,216.00	5,503.00	6,442.26	5,729.26	226.26	3.64	226.26	4.11	14.81	13.11	15.35	13.65
30	50,370	6,844.74	6,131.74	7,050.01	6,337.01	205.27	3.00	205.27	3.35	13.59	12.17	14.00	12.58
35	58,765	7,433.23	6,720.23	7,617.51	6,904.51	184.29	2.48	184.29	2.74	12.65	11.44	12.96	11.75
40	67,160	8,021.72	7,308.72	8,185.02	7,472.02	163.30	2.04	163.30	2.23	11.94	10.88	12.19	11.13
45	75,555	8,610.21	7,897.21	8,752.52	8,039.52	142.31	1.65	142.31	1.80	11.40	10.45	11.58	10.64
50	83,950	9,198.70	8,485.70	9,320.02	8,607.02	121.32	1.32	121.32	1.43	10.96	10.11	11.10	10.25
55	92,345	9,783.73	9,070.73	9,884.07	9,171.07	100.34	1.03	100.34	1.11	10.59	9.82	10.70	9.93
60	100,740	10,288.27	9,575.27	10,367.62	9,654.62	79.35	0.77	79.35	0.83	10.21	9.50	10.29	9.58
65	109,135	10,792.81	10,079.81	10,851.18	10,138.18	58.36	0.54	58.36	0.58	9.89	9.24	9.94	9.29
70	117,530	11,297.35	10,584.35	11,334.73	10,621.73	37.37	0.33	37.37	0.35	9.61	9.01	9.64	9.04
75	125,925	11,801.89	11,088.89	11,818.28	11,105.28	16.39	0.14	16.39	0.15	9.37	8.81	9.39	8.82
80	134,320	12,306.43	11,593.43	12,301.83	11,588.83	(4.60)	(0.04)	(4.60)	(0.04)	9.16	8.63	9.16	8.63
85	142,715	12,810.97	12,097.97	12,785.38	12,072.38	(25.59)	(0.20)	(25.59)	(0.21)	8.98	8.48	8.96	8.48
90	151,110	13,315.51	12,602.51	13,268.94	12,555.94	(46.58)	(0.35)	(46.58)	(0.37)	8.81	8.34	8.78	8.31
95	159,505	13,820.05	13,107.05	13,752.49	13,039.49	(67.56)	(0.49)	(67.56)	(0.52)	8.66	8.22	8.62	8.17
100	167,900	14,324.59	13,611.59	14,236.04	13,523.04	(88.55)	(0.62)	(88.55)	(0.65)	8.53	8.11	8.48	8.05

Comparison of Present and Proposed Rates
Full Interruptible Service (70)
Based on 450 kW - Assume Zero Coincidental Demand

Present			**Proposed**		
Fixed Charge	$110.00	/mo.	Fixed Charge	$130.00	/mo.
Demand Charge			Demand Charge		
Summer	$24.85	/kW	Summer	$26.14	/kW
Winter	$18.95	/kW	Winter	$19.91	/kW
Other	$13.00	/kW	Other	$13.67	/kW
Non-coinc	$4.75	/kW	Non-coinc	$5.25	/kW
Energy Charge	$0.04990	/kWh	Energy Charge	$0.05210	/kWh
RTA Charge	(0.0005)	/kWh			

Avg. Load Factor	kWh/ Mo.	Billing Present	Billing Proposed	Present vs. Proposed Incr./(Decr.)		Average Rate Present	Average Rate Proposed
(%)	(kWh/mo)	($)	($)	($)	(%)	(¢/kWh)	(¢/kWh)
-	-	2,247.50	2,492.50	245.00	10.90	N.A.	N.A.
5	16,425	3,058.90	3,348.24	289.34	9.46	18.62	20.39
10	32,850	3,870.29	4,203.99	333.70	8.62	11.78	12.80
15	49,275	4,681.69	5,059.73	378.04	8.07	9.50	10.27
20	65,700	5,493.08	5,915.47	422.39	7.69	8.36	9.00
25	82,125	6,304.48	6,771.21	466.73	7.40	7.68	8.25
30	98,550	7,115.87	7,626.96	511.09	7.18	7.22	7.74
35	114,975	7,927.27	8,482.70	555.43	7.01	6.89	7.38
40	131,400	8,738.66	9,338.44	599.78	6.86	6.65	7.11
45	147,825	9,550.06	10,194.18	644.12	6.74	6.46	6.90
50	164,250	10,361.45	11,049.93	688.48	6.64	6.31	6.73
55	180,675	11,172.85	11,905.67	732.82	6.56	6.18	6.59
60	197,100	11,984.24	12,761.41	777.17	6.48	6.08	6.47
65	213,525	12,795.64	13,617.15	821.51	6.42	5.99	6.38
70	229,950	13,607.03	14,472.90	865.87	6.36	5.92	6.29
75	246,375	14,418.43	15,328.64	910.21	6.31	5.85	6.22
80	262,800	15,229.82	16,184.38	954.56	6.27	5.80	6.16
85	279,225	16,041.22	17,040.12	998.90	6.23	5.74	6.10
90	295,650	16,852.61	17,895.87	1,043.26	6.19	5.70	6.05
95	312,075	17,664.01	18,751.61	1,087.60	6.16	5.66	6.01
100	328,500	18,475.40	19,607.35	1,131.95	6.13	5.62	5.97

Docket No. E-111/GR-19-478

Exhibit__(DEA-5)
Statement of Operations -
Proposed Rates

Statement of Operations
Proposed Rates
Test Year - 2018 Historical Adjusted

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Adjustments [1]	(e) Pro Forma Test Year
1	**Operating Revenue**	($)	($)	($)
2	Rate Schedules	202,630,477	6,498,007	209,128,484 [2]
3	Other	508,198	626,590	1,134,788
4	**Total Operating Revenue**	203,138,675	7,124,597	210,263,272
5	**Operating Expenses**			
6	Cost of Purchased Power	149,330,034	1,319,432	150,649,466
7	Transmission - O & M	-		-
8	Distribution - Operation	7,277,184	(383,045)	6,894,139
9	Distribution - Maintenance	6,151,338	242,574	6,393,912
10	Consumer Accounts	5,312,955	380,854	5,693,809
11	Consumer Service & Information	3,585,760	(180,461)	3,405,299
12	Sales	-	-	-
13	Administrative & General	11,907,838	71,783	11,979,621
14	Depreciation & Amortization	10,281,975	404,073	10,686,048
15	Taxes - Property	3,372,283	178,507	3,550,790
16	Taxes - Other	-	-	-
17	Other Interest Expense	549,008	-	549,008
18	Other Deductions	6,239	(38,705)	(32,466)
19	**Total Operating Expenses** (Before Long Term Interest)	197,774,614	1,995,012	199,769,626
20	**Net Operating Income** (Before Long Term Interest)	5,364,061	5,129,585	10,493,646

[1] The operating expense adjustments are summarized on page 2 of Exhibit__(DEA-1).
[2] See pages 2 through 10 for an estimate of the Pro Forma Test Year revenue under proposed rates.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

I. Consumer and Sales Data for Pro Forma Test Year

(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**Avg. No. Cons.**	**Energy Sales** [1]	**Billing Demand**	**Revenue** [2]
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	100,202	838,089,528	N.A.	119,389,671
2	Residential & Farm Demand Control (32)	15	378,000	917.2	44,529
3	Electric Vehicle (33)	88	300,960	N.A.	26,505
4	Irrigation Service (36) Firm	8	162,528	1,867.3	50,484
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	883,153
6	Small General Service (41)	4,431	42,537,600	N.A.	6,197,337
7	Security Lighting Service (44) - Closed to New	878	405,600	N.A.	120,526
8	Street Lighting Service (44-2)	2,269	2,405,280	N.A.	524,779
9	Street Lighting System (44-1)	470	521,040	N.A.	88,142
10	Custom Residential Street Lighting (44-3)	12,190	6,750,960	N.A.	1,623,968
11	LED Security Lighting Service (44 -4)	356	64,896	N.A.	31,434
12	LED Street Lighting Member Owned(44-5)	11	8,712	N.A.	1,473
13	LED Street Lighting (44-6)	597	202,152	N.A.	57,768
14	Low Wattage Unmetered Service (45)	71	-	N.A.	8,946
15	General Service (46)	2,750	462,000,000	1,442,500.4	51,183,966
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	3	172,800	N.A.	17,798
18	Controlled Energy Storage (51)	1,718	10,308,000	N.A.	502,001
19	Controlled Interruptible Service (52)	6,686	44,127,600	N.A.	2,784,452
20	Residential & Farm Time of Day (53)	18	216,216	N.A.	30,323
21	General Service Time of Day (54)	6	1,059,984	6,802.3	130,543
22	Standby Service (60)	1	-	-	74,160
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	24,654,929
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,299,459
25	Cycled Air Conditioning Service (80)	41,880	379,080,000		(1,625,193)
26	Wellspring				23,370
27	**Total** [3]	108,168	1,824,313,200	2,496,964.3	209,128,484

[1] See Exhibit__(DEA-1), page 13.
[2] See Exhibit__(DEA-5), pages 3 through 9.
[3] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

II. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Residential & Farm Service (31)				($)
Fixed Charge	100,202	cons.	$10.00	12,024,240
Energy Charge				
Summer	257,025,312	kWh	$0.13790	35,443,791
Other	581,064,216	kWh	$0.12390	71,993,856
	838,089,528	kWh	Subtotal	119,461,887
RTA Charge [1]	838,089,528	kWh		
Controlled Water Heater Credit	1,003	units	($6.00)	(72,216)
			Total	119,389,671
Residential & Farm Demand Control (32)				
Fixed Charge	15	cons.	$13.00	2,340
Demand Charge				
Summer	182.2	kW	$15.50	2,824
Other	735.0	kW	$11.90	8,747
Energy Charge	378,000	kWh	$0.08100	30,618
			Subtotal	44,529
RTA Charge [1]	378,000	kWh		
			Total	44,529
Electric Vehicle (33)				
Energy Charge				
Off Peak	280,402	kWh	$0.07560	21,198
On Peak	8,554	kWh	$0.44210	3,782
Other				
Summer	2,693	kWh	$0.13790	371
Other	9,311	kWh	$0.12390	1,154
			Subtotal	26,505
RTA Charge [1]	300,960	kWh		
				26,505
Irrigation Service (36)				
Firm Service				
Fixed Charge	8	cons.	$30.00	2,880
Demand Charge				
Summer	902.3	kW	$26.60	24,001
Winter	2.5	kW	$21.20	53
Other	962.5	kW	$15.67	15,082
Energy Charge	162,528	kWh	$0.05210	8,468
RTA Charge [1]	162,528	kWh		
			Total	50,484

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

II. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Irrigation Service (36)				
Interruptible Service				
Fixed Charge	384	cons.	$30.00	138,240
Demand Charge	74,388	kW	$4.55	338,463
Energy Charge	7,801,344	kWh	$0.05210	406,450
RTA Charge [1]	7,801,344	kWh		
			Total	883,153
Small General Service (41)				
Fixed Charge				
Energy Charge	4,431	cons.	$15.00	797,580
Summer	10,541,910	kWh	$0.13750	1,449,513
Other	31,995,690	kWh	$0.12350	3,951,468
	42,537,600	kWh	Subtotal	6,198,561
RTA Charge [1]	42,537,600	kWh		
Controlled Water Heater Credit	17	units	($6.00)	($1,224)
			Total	6,197,337
Security Lighting Service (44) - Closed to New				
175 W MV		lights	N/A	
100 W HPS	819	lights	$12.01	118,034
150 W HPS	4	lights	$14.26	684
250 W HPS	8	lights	$18.83	1,808
	831	lights	Subtotal	120,526
RTA Charge [1]	405,600	kWh		
			Total	120,526
Street Lighting Service (44-2)				
175 W MV		lights	$17.44	
250 W MV	3	lights	$20.93	753
400 W MV		lights	$26.89	
100 W HPS	38	lights	$13.80	6,293
150 W HPS	646	lights	$15.97	123,799
250 W HPS	1,597	lights	$20.54	393,629
400 W HPS	1	lights	$25.42	305
	2,285	lights	Subtotal	524,779
RTA Charge [1]	2,405,280	kWh		
			Total	524,779

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Street Lighting System (44-1)				($)
175 W MV		lights	$13.25	
250 W MV		lights	$16.74	
400 W MV		lights	$22.71	
100 W HPS		lights	$9.61	
150 W HPS	101	lights	$11.78	14,277
200 W HPS	101	lights	$14.18	17,186
250 W HPS	272	lights	$16.35	53,366
400 W HPS	13	lights	$21.24	3,313
	487	lights	Subtotal	88,142
RTA Charge [1]	521,040	kWh		
			Total	88,142
Custom Residential Street Lighting (44-3)				
175 W MV		lights	$14.03	
50 W HPS	81	lights	$8.45	8,213
100 W HPS	8,416	lights	$10.39	1,049,307
150 W HPS	3,732	lights	$12.63	565,622
250 W HPS	4	lights	$17.21	826
	12,233	lights	Subtotal	1,623,968
RTA Charge [1]	6,750,960	kWh		
			Total	1,623,968
LED Security Lighting Service (44 -4)				
LED, >4,500 Lumens	338	lights	$7.75	31,434
RTA Charge [1]	64,896	kWh		
			Total	31,434

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
LED Street Lighting Member Owned(44-5)				($)
A (40-80 watts)		lights	$5.50	
B (81-150 watts)		lights	$7.75	
C (151-250 watts)	11	lights	$11.16	1,473
D (251-350 watts)		lights	$15.04	
E (351-450 watts)		lights	$19.07	
				1,473
RTA Charge [1]	8,712	kWh		
				1,473
LED Street Lighting (44-6)				
Standard				
>5,200 L, Coach (Post)	121	lights	$9.30	13,504
>5,200 L, Acorn (Post)	48	lights	$10.85	6,250
>7,000 L, Cobra (Mast)	91	lights	$8.60	9,391
>11,500 L, Shoebox	151	lights	$10.70	19,388
Basic				
>5,200 L, Coach (Post)	41	lights	$6.36	3,129
>5,200 L, Acorn (Post)		lights	$6.12	
>7,000 L, Cobra (Mast)	53	lights	$6.98	4,439
>11,500 L, Shoebox	16	lights	$8.68	1,667
				57,768
RTA Charge [1]	202,152	kWh		
				57,768
Low Wattage Unmetered Service (45)				
Fixed Charge	71	cons.	$10.50	8,946

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
General Service (46)				
Fixed Charge	2,750	cons.	$34.00	1,122,000
Demand Charge	1,442,500.4	kW		
Summer	413,627.7			
Summer Load Adjustment	(11,771.4)			
Net Summer	401,856.3	kW	$13.70	5,666,699
Other	1,028,872.7			
Other Load Adjustment	(21,406.1)			
Net Other	1,007,466.6	kW	$10.60	10,906,051
Energy Charge				
First 200 kWh/kW	264,418,387	kWh	$0.07760	20,518,867
Next 200 kWh/kW	158,964,776	kWh	$0.06760	10,746,019
Over 400 kWh/kW	38,616,837	kWh	$0.05760	2,224,330
			Subtotal	51,183,966
Discounts				
Primary Voltage			($0.15)	
Primary Metering			(2.00%)	
RTA Charge 1	462,000,000			
			Total	51,183,966
Municipal Civil Defense Sirens (47)		kWh		
Fixed Charge	66	cons.	$5.00	3,960
Geothermal Heat Pump (49)				
Energy Charge	172,800	kWh	$0.10300	17,798
RTA Charge [1]	172,800	kWh		
			Total	17,798
Controlled Energy Storage (51)				
Energy Net Charge - Rate 31				
Summer	2,701,434	kWh	$0.04870	131,560
Other	7,509,011	kWh	$0.04870	365,689
Energy Charge - Rate 41				
Summer	6,874	kWh	$0.04870	335
Other	39,232	kWh	$0.04870	1,911
Energy Charge - Rate 46	51,449	kWh	$0.04870	2,506
			Subtotal	502,001
RTA Charge [1]	10,308,000	kWh	NA	
			Total	502,001

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Controlled Interruptible Service (52)				($)
Energy Net Charge - Rate 31				
Summer	10,488,495	kWh	$ 0.0631	661,824
Other	32,538,130	kWh	0.0631	2,053,156
Energy Charge - Rate 41		kWh		
Summer	64,095	kWh	$0.06310	4,044
Other	386,791	kWh	$0.06310	24,407
Energy Charge - Rate 46	650,089		$0.06310	41,021
RTA Charge [1]	44,127,600		NA	
			Total	2,784,452
Residential & Farm Time of Day (53)				
Fixed Charge	18	cons.	$13.00	2,808
Energy Charge				
Peak Period				
Summer	49,267	kWh	$0.21263	10,476
Other	12,117	kWh	$0.19863	2,407
Off-Peak Period	154,832	kWh	$0.09450	14,632
	216,216	kWh	Subtotal	30,323
RTA Charge [1]	216,216	kWh		
			Total	30,323
General Service Time of Day (54)				
Fixed Charge	6	cons.	$36.00	2,592
Demand Charge				
Peak Period				
Summer	960.1	kW	$26.14	25,097
Winter	436.9	kW	$19.91	8,699
Other	1,253.2	kW	$13.67	17,131
	2,650.2	kW		
Maximum	4,152.1	kW	$5.25	21,799
Energy Charge	1,059,984	kWh	$0.05210	55,225
			Subtotal	130,543
Discounts				
Primary Voltage		kW	($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	1,059,984	kWh		
			Total	130,543

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Standby Service (60)				
Generation Reservation Fee				
Summer	1,000	kW	$3.21	9,630
Winter	1,000	kW	$2.47	7,410
Other	1,000	kW	$1.74	10,440
Distribution Reservation Fee				
Primary	1,000	kW	$3.89	46,680
Secondary		kW	$4.02	
			Total	74,160
Full Interruptible Service (70)				
Fixed Charge	234	cons.	$130.00	365,040
Communication Fee	51		$8.70	5,324
Coinc. Demand Charge				
Summer	1,042.8	kW	$26.14	27,259
Winter		kW	$19.91	
Other		kW	$13.67	
Total Coinc Demand	1,042.8	kW		
Non-Coinc. Demand	858,880.1	kW	$5.25	4,509,121
Failure to Control	1,042.8	kW	$5.00	5,214
Energy Charge	379,080,000	kWh	$0.05210	19,750,068
Discounts			Subtotal	24,662,026
Primary Voltage	47,311.1	kW	($0.15)	($7,097)
Primary Metering			(2.0%)	
RTA Charge [1]	379,080,000	kWh		
			Total	24,654,929
Partial Interruptible Service (71)				
Fixed Charge	28	cons.	$130.00	43,680
Communication Fee	17		$8.70	1,775
Coinc. Demand Charge				
Summer	3,212.2	kW	$26.14	83,967
Winter	2,980.2	kW	$19.91	59,336
Other	5,964.3	kW	$13.67	81,532
Total Coinc Demand	12,156.7	kW		
Non-Coinc. Demand	111,609.5	kW	$5.25	585,950
Excess Demand		kW	$5.00	
Energy Charge	27,720,000	kWh	$0.05210	1,444,212
Discounts			Subtotal	2,300,452
Primary Voltage	6,623	kW	$0.15	(993)
Primary Metering			2.0%	-
RTA Charge [1]	27,720,000	kWh		
			Total	2,299,459

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Cycled Air Conditioning Service (80)				
Option 1		kWh		
Option 2				
Residential Rate 8131	4,858,654	kWh	($0.03200)	(155,477)
Rate 8141	216,346	kWh	($0.03200)	(6,923)
Rate 8146		kWh	($0.03200)	
	5,075,000	kWh		(162,400)
Option 3				
Residential Rate 8231	35,158	cons.	($13.00)	(1,371,162)
Commercial		cons.	($13.00)	
				(1,371,162)
Option 4				
Rate 8441	4,699	tons	($6.50)	(91,631)
Rate 8446		tons	($6.50)	
	4,699			(91,631)
				(1,625,193)
			Total	
Wellspring				23,370
Grand Total	1,824,313,200			209,128,484

[1] Proposed rates assume zero RTA.

Docket No. E-111/GR-19-478

Exhibit__(DEA-4)
Load Management Cost Analysis

Summary of Cost of Service Analysis
Load Management Rates
I. Summary

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Rate Description	**GRE Rate** (¢/kWh)	**Line Losses** (¢/kWh)	**Meter & Control** (¢/kWh)	**Allocated Distribution** (¢/kWh)	**Margin** (¢/kWh)	**Total Cost** (¢/kWh)	**Weighted Sales** (%)	**Retail Rate** (¢/kWh)
Schedule 49								
Geothermal Heat Pump	8.13 [2]	0.12	0.42	2.13	0.27	11.07	100%	**11.07**
Schedule 51 (Storage)								
ETS-Water Heating (16 hr)	2.00	0.12	0.42	2.13	0.07	4.74	49%	2.32
ETS-Storage [1]	2.25	0.12	0.42	2.13	0.08	5.00	51%	2.55
							Schedule 51 Rate	**4.87**
Schedule 52 (Interruptible)								
Peak Shave - Water (8 hr)	3.40	0.12	0.42	2.13	0.11	6.18	53%	3.28
Dual Fuel - Space Heating	3.65	0.12	0.42	2.13	0.12	6.44	47%	3.03
							Schedule 52 Rate	**6.31**

Col.	**Notes**
(a)	Load management rates per GRE's present wholesale rate schedules.
(b)	Based on GRE wholesale rate schedules for Year 2019.
(c)	GRE General Service Energy Rate x 2.50% which represents the average losses for the system.
(d)	See page 2.
(e)	See page 4.
(f)	See page 3 for calculation of margin.
(g)	Sum Col. (b) to Col. (f).
(h)	Relative (percent) energy sales under each GRE special program. See Exhibit __ (DEA-1) Page 22 of 22.
(i)	Equals Total Cost times Weighted Sales. Sum equals retail rate of each schedule.

[1] This rate may also apply to loads qualifying under the ETS Pool Heating program and/or Electric Vehicles program.
[2] Geothermal equals GRE average energy rate plus average system capacity, transmission, and ancillary services costs on a per kWh basis.

Cost of Service Analysis
Load Management Rates
(Continued)

II. Cost of Service Analysis

A. Incremental Cost of Service

1. Annual Cost of Control Unit and Meter
   a. Investment

1. Meter	$53
2. Control Unit	$134
3. Subtotal	$187

   b. Annual Cost Factor
      1. Capital Recovery Factor [1]

$$\frac{0.0420 \times (1.0420)^{15}}{1.0420^{15} - 1} = 9.1\%$$

      2. Operation & Maintenance

O & M Expense / Dist. Plant [2]	$13,288,051 / $267,355,082	=	5.0%
	Total		14.1%

   c. Annual Cost $187.00 x 14.1% = $26.35 /year

   d. Per kWh Cost [3]   0.42 ¢/kWh

2. Purchased Power
   a. At present wholesale energy rate adjusted for load management programs. See Page 1.

   b. Average system losses for test year = 2.50%

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[1] The incremental interest rate is estimated as follows:

CFC-15 yr	1.00	x	4.2000%	=	4.2000%

[2] Data taken from Form 7 for December, 2018. See workpaper 1.
[3] Based on annual use of 6,300 kWh per year.

Cost of Service Analysis
Load Management Rates
(Continued)

II. Cost of Service Analysis (Continued)

A. Incremental Cost of Service (Continued)

3. Margin Requirement (Equity Portion Only) [1]

$$\frac{\text{Required Net Operating Income - Interest Expense}}{\text{Total Expenses + Required Net Operating Income}}$$

$$\frac{\$10{,}538{,}868 \quad - \quad \$3{,}766{,}478}{\$199{,}769{,}626 \quad + \quad \$10{,}538{,}868} = 3.2202\%$$

B. Allocated Cost of Service (Full Share)

1. Distribution System Capacity

a. Depreciation (Acct. 403)		$10,686,048	
b. Interest (Acct. 427)		3,766,478	
c. Operation and Maintenance (Accts. 580 to 598)		13,288,051	
d. Total		$27,740,577	
e. Energy Sales		1,824,313,200	kWh
f. Unit Cost (Unadjusted)		1.52	¢/kWh
g. Allocation Factor [2]	x	50.00%	
h. Allocation Cost		0.76	¢/kWh

2. Administration and General

$$\frac{\text{Accounts 920 to 930}}{\text{Total Energy Sales}} = \frac{\$11{,}979{,}621}{1{,}824{,}313{,}200 \text{ kWh}} = 0.66 \text{ ¢/kWh}$$

[1] Interest expense is reflected in the "annual cost factor". Margin is to cover the patronage capital which will be allocated to each consumer on the basis of all other costs which is somewhat analogous to revenue.

[2] Factor to be used to allocate distribution system related cost to the off-peak class. Use 0.5000 as this approximates the capacity related distribution system costs in the listed categories.

Cost of Service Analysis
Load Management Rates
(Continued)

B. Allocated Cost of Service (Full Share) (Continued)

3. Consumer Accounting

$$\frac{\text{Accounts 901 to 905 x Weight Factor}^{1}}{\text{Total No. of Cons. x Off-Peak Usage}}$$

$$\frac{\$5{,}693{,}809 \quad \text{x} \quad 0.50}{108{,}165 \quad \text{x} \quad 6{,}300 \text{ kWh}^{2}}$$ 0.42 ¢/kWh

4. Taxes

$$\frac{\text{Account 408}}{\text{Total Energy Sales}}$$

$$\frac{\$3{,}550{,}790}{1{,}824{,}313{,}200 \text{ kWh}}$$ 0.19 ¢/kWh

5. Consumer Service & Sales [3] 0.10 ¢/kWh

6. Total Allocated Costs (Before Margin Requirement) 2.13 ¢/kWh

[1] Use a weighting factor of 0.5 to represent the amount of consumer accounting expense to be allocated to this class.
[2] Estimate the annual usage for a typical system to be 6,300 kWh per year based on Pro Forma Test Year Sales.
[3] This factor is based on the judgment of management as to the special cost assocated with providing information and customer service for this type of load.

Docket No. E-111/GR-19-478

Exhibit (DEA-3)
Cost of Service Analysis

Cost of Service Summary
Revenue Requirements Summary

Line No.	Description	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Revenue Requirements**							
2	Revenue Requirements	207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469
3								
4	**Present Rates**							
5	Revenue-Present Rates	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
6	Other Operating Revenue	1,100,791	629,957	31,817	5,091	281,211	141,172	11,543
7	Total Revenue	198,343,047	113,507,080	5,732,872	917,323	50,669,263	25,436,728	2,079,781
8								
9	Difference	8,727,396	5,968,415	509,411	(24,816)	(132,811)	2,018,508	388,689
10	Percent		5.29%	8.94%	(2.72%)	(0.26%)	7.98%	18.79%

Cost of Service Summary
Class Allocation Summary

Line No.	Category	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Power Supply**							
2	**Direct and Revenue Related**							
3	Wholesale Cost							
4	Allocated Cost							
5	Subtotal							
6	**Capacity Related**							
7	Wholesale Cost	33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
8	Allocated Cost	328,991	198,146	10,188	183	105,776	12,878	1,819
9	Subtotal	33,843,058	20,979,277	1,042,559	25,042	11,476,666	162,728	156,786
10	**Energy Related**							
11	Wholesale Cost	92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
12	Allocated Cost	892,910	420,872	21,278	4,042	235,006	206,454	5,257
13	Subtotal	93,803,557	44,478,179	2,255,842	422,396	24,560,237	21,576,264	510,639
14	Subtotal Power Supply	127,646,615	65,457,456	3,298,400	447,438	36,036,904	21,738,992	667,425
15	**Transmission**							
16	Direct							
17	Capacity	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
18	Energy							
19	Allocated Cost							
20	Subtotal Transmission	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
21	**Distribution**							
22	Direct	1,446,444						1,446,444
23	Consumer	35,017,518	30,207,652	1,736,178	269,591	2,007,933	695,080	101,085
24	Capacity	20,310,243	10,113,625	501,599	162,967	5,261,940	4,140,938	129,175
25	Energy							
26	Subtotal Distribution	56,774,205	40,321,277	2,237,776	432,558	7,269,873	4,836,017	1,676,703
27								
28	**Total**	207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Cost of Service Summary
Rate Design Factors

Line No.	Category	Units	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Costs Broken Down by Function**							
2	**Power Supply**							
3	**Direct and Revenue Related**							
4	Wholesale Cost	$/Mo./cons						
5	Allocated Cost	$/Mo./cons						
6	Subtotal							
7	**Capacity Related**							
8	Wholesale Cost	¢/kWh	2.48	2.43	0.31	2.46	0.04	1.50
9	Allocated Cost	¢/kWh	0.02	0.02	0.00	0.02	0.00	0.02
10	Subtotal	¢/kWh	2.50	2.45	0.31	2.48	0.04	1.51
11	**Energy Related**							
12	Wholesale Cost	¢/kWh	5.25	5.25	5.25	5.25	5.25	4.88
13	Allocated Cost	¢/kWh	0.05	0.05	0.05	0.05	0.05	0.05
14	Subtotal	¢/kWh	5.30	5.30	5.30	5.30	5.30	4.93
15	Subtotal Power Supply	¢/kWh	7.80	7.75	5.62	7.78	5.34	6.44
16	**Transmission**							
17	Direct	¢/kWh						
18	Capacity	¢/kWh	1.63	1.66	0.16	1.56	0.22	1.20
19	Energy	¢/kWh						
20	Allocated Cost	¢/kWh						
21	Subtotal Transmission	¢/kWh	1.63	1.66	0.16	1.56	0.22	1.20
22	**Distribution**							
23	Direct	$/Mo./cons						7.19
24	Consumer	$/Mo./cons	25.11	32.65	57.31	60.71	221.08	0.50
25	Capacity	¢/kWh	1.21	1.18	2.05	1.14	1.02	1.25
26	Energy	¢/kWh						
27	Subtotal Distribution	¢/kWh	4.81	5.26	5.43	1.57	1.19	16.19
28	**Total**	¢/kWh	14.25	14.67	11.21	10.91	6.75	23.83
29	**Costs Broken Down by Classification**							
30	Direct	$/Mo./cons						7.19
31	Consumer	$/Mo./cons	25.11	32.65	57.31	60.71	221.08	0.50
32	Capacity	¢/kWh	5.34	5.29	2.52	5.18	1.27	3.96
33	Energy	¢/kWh	5.30	5.30	5.30	5.30	5.30	4.93
34	**Total**		14.25	14.67	11.21	10.91	6.75	23.83

Classification of Plant in Service (Net)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Net Intangible Plant**																
2	301	Organization	PLNT															
3	302	Franchises and consents	PLNT															
4	303	Miscellaneous intangible plant	PLNT															
5	301-303	Subtotal																
6																		
7		**Net Production Plant**																
8	310-346	Production Plant	PROD1															
9																		
10		**Net Transmission Plant**																
11	350-359	Transmission Plant	TRAN1															
12																		
13		**Net Distribution Plant**																
14	360	Land	LAND	4,163,712					4,163,712									
15	361	Structures	SUB															
16	362	Station	SUB	18,856,408					18,856,408									
17	363	Battery	SUB															
18	364	Poles, towers	POLES	10,796,888							4,750,137	6,046,751						
19	365	OH Cond	PRI-OH	13,738,437							2,414,494	11,323,943						
20	366	UG Conduit	PRI-UG															
21	367	UG Cond	PRI-UG	84,374,330							63,512,819	20,861,511						
22	368	Transf	TRF	17,481,215									3,443,783	14,037,432				
23	369	Services	SERV	1,190,394											1,190,394			
24	370	Meters	MTR	2,686,182												2,686,182		
25	371	Cons Premise	ICON	123,745														
26	372	Leased Prop	LICON															
27	373	St. Light	STL	4,543,471														
28	360-373	Subtotal		157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
29																		
30		**Net General Plant**																
31	389	Land & Land Rights	PLNT	102,278					14,906		45,765	24,756	2,230	9,089	771	1,739		
32	390	Structures and Improve.	PLNT	4,601,923					670,678		2,059,148	1,113,874	100,333	408,973	34,681	78,260		
33	391	Office Furniture & Equip.	PLNT	5,056,678					736,954		2,262,629	1,223,945	110,247	449,387	38,109	85,994		
34	392	Transportation & Equipment	PLNT	918,591					133,874		411,027	222,341	20,027	81,635	6,923	15,622		
35	393	Stores Equipment	PLNT	18,982					2,766		8,494	4,595	414	1,687	143	323		
36	394	Tool, Shop & Garage Equip.	PLNT	156,304					22,780		69,939	37,833	3,408	13,891	1,178	2,658		
37	395	Laboratory Equipment	PLNT	209,246					30,495		93,628	50,647	4,562	18,596	1,577	3,558		
38	396	Power Operated Equipment	PLNT	3,930,565					572,835		1,758,746	951,375	85,695	349,309	29,622	66,843		
39	397	Communication Equipment	PLNT	345,799					50,396		154,729	83,699	7,539	30,731	2,606	5,881		
40	398	Miscellaneous Equipment	PLNT	84,672					12,340		37,887	20,495	1,846	7,525	638	1,440		
41	399	Other tangible property	PLNT	633,349					92,304		283,395	153,299	13,808	56,286	4,773	10,771		
42	389-399	Subtotal		16,058,389					2,340,328		7,185,385	3,886,857	350,110	1,427,108	121,021	273,089		
43																		
44		**Total Net Plant in Service**		174,013,170					25,360,448		77,862,835	42,119,061	3,793,893	15,464,540	1,311,415	2,959,271		

Classification of Plant in Service (Net)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
1		**Net Intangible Plant**								
2	301	Organization	PLNT							
3	302	Franchises and consents	PLNT							
4	303	Miscellaneous intangible plant	PLNT							
5	301-303	Subtotal								
6										
7		**Net Production Plant**								
8	310-346	Production Plant	PROD1							
9										
10		**Net Transmission Plant**								
11	350-359	Transmission Plant	TRAN1							
12										
13		**Net Distribution Plant**								
14	360	Land	LAND	4,163,712						
15	361	Structures	SUB							
16	362	Station	SUB	18,856,408						
17	363	Battery	SUB							
18	364	Poles, towers	POLES	10,796,888						
19	365	OH Cond	PRI-OH	13,738,437						
20	366	UG Conduit	PRI-UG							
21	367	UG Cond	PRI-UG	84,374,330						
22	368	Transf	TRF	17,481,215						
23	369	Services	SERV	1,190,394						
24	370	Meters	MTR	2,686,182						
25	371	Cons Premise	ICON	123,745						123,745
26	372	Leased Prop	LICON							
27	373	St. Light	STL	4,543,471						4,543,471
28	360-373	Subtotal		157,954,781						4,667,216
29										
30		**Net General Plant**								
31	389	Land & Land Rights	PLNT	102,278						3,022
32	390	Structures and Improve.	PLNT	4,601,923						135,977
33	391	Office Furniture & Equip.	PLNT	5,056,678						149,414
34	392	Transportation & Equipment	PLNT	918,591						27,142
35	393	Stores Equipment	PLNT	18,982						561
36	394	Tool, Shop & Garage Equip.	PLNT	156,304						4,618
37	395	Laboratory Equipment	PLNT	209,246						6,183
38	396	Power Operated Equipment	PLNT	3,930,565						116,140
39	397	Communication Equipment	PLNT	345,799						10,218
40	398	Miscellaneous Equipment	PLNT	84,672						2,502
41	399	Other tangible property	PLNT	633,349						18,714
42	389-399	Subtotal		16,058,389						474,490
43										
44		**Total Net Plant in Service**		174,013,170						5,141,706

**Adjusted Statement of Operations
and Revenue Requirements**

(a) Line No.	(b) Description	(c) Total System [1]	(d) Adjustment [2]	(e) Adjusted System
	Operating Revenue	($)	($)	($)
1	Rate Schedules	200,474,161	(3,238,029)	197,236,132
2	Other	1,100,791		1,100,791
3	Total Operating Revenue	201,574,952	(3,238,029)	198,336,923
4	**Operating Expenses**			
5	Cost of Purchased Power			
6	Substation	-	-	-
7	Transmission	20,496,973		20,496,973
8	Ancillary	2,152,650		2,152,650
9	Demand			-
10	Summer	17,112,830		17,112,830
11	Winter	8,390,047		8,390,047
12	Other	8,011,190		8,011,190
	Energy			-
13	Wholesale Solar	272,629		272,629
14	Energy On-Peak	36,623,232	(424,870)	36,198,362
15	Energy Off-Peak	57,584,525	(1,144,869)	56,439,656
16	Standby Reservation fee	27,060	(27,060)	-
16	Wellspring	23,370	(23,370)	-
	Member Specific Rate	(45,040)	45,040	-
16	Transmission - O & M		-	-
18	Distribution - Operation	6,894,139	(277,154)	6,616,985
19	Distribution - Maintenance	6,393,912	(277,154)	6,116,758
20	Consumer Accounts	5,693,809	-	5,693,809
21	Consumer Service & Information	3,405,299	-	3,405,299
22	Sales	-	-	-
23	Administrative & General	11,979,621	(277,154)	11,702,467
24	Depreciation & Amortization	10,686,048	(277,154)	10,408,894
25	Taxes - Property	3,550,790	-	3,550,790
26	Taxes - Other	-	-	-
27	Other Interest Expense	549,008	-	549,008
28	Other Deductions	(32,466)	-	(32,466)
29	**Total Operating Expenses (Before Long Term Interest)**	199,769,626	(2,683,745)	197,085,881
30	Long Term Interest [3]	3,766,478	(277,154)	3,489,324
31	Required Margin [4]	6,772,390	(277,152)	6,495,238
32	**Revenue Requirements**	210,308,494	(3,238,051)	207,070,443

[1] See Exhibit__(DEA-1), page 1.

[2] See page 7 for calculation of adjustment to exclude Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating Service, and Low Wattage Unmetered Service.

[3] See Workpaper 1.

[4] Required Net Operating Income less Long Term Interest. See calculation below:
$10,538,868 - $3,766,478 = $6,772,390

Adjustment to Eliminate Revenue and Expenses
of Classes not included in the Base Cost of Service Study

1. Revenue [1]

			($)
a.	Electric Vehicle (33)	=	24,636
b.	Municipal Civil Defense Sirens (47)	=	3,960
c.	Controlled Energy Storage (51)	=	459,736
d.	Controlled Interruptible Service (52)	=	2,634,418
e.	Low Wattage Unmetered Service (45)	=	8,520
f.	Geothermal Heat Pump (49) Closed to New	=	16,571
g.	Standby Service (60)	=	66,840
h.	Wellspring	=	23,370
i.	Total -- Revenue		3,238,051

2. Expenses

a. Purchased Power [2]						
Energy:						
Electric Vehicle (33)	264,300	kWh	x	0.0200	=	5,286
Municipal Civil Defense Sirens (47)					=	-
ETS-Interruptible Water Heating 3	6,187,000	kWh	x	0.02000	=	123,740
Peak Shave Water Heating (8 hr) 3	21,206,900	kWh	x	0.03400	=	721,035
ETS-Interruptible Space Heating 3	1,323,100	kWh	x	0.02250	=	29,770
Dual Fuel 3	18,516,900	kWh	x	0.03650	=	675,867
Geothermal Heat Pump	172,800	kWh	x	0.05087	=	8,790
Subtotal -- Energy Expenses						1,564,488
Standby	27,060	/year			=	27,060
Wellspring	23,370	/year			=	23,370
Member Specific Rate	(45,040)	/year			=	(45,040)
Capacity - Geothermal	172,800	kWh	x	0.03039		5,251
Subtotal -- Purchased Power Expenses						1,575,129

Remainder of Revenue to Allocate 1,662,922

b.	Distribution - Operation [3]	=	277,154
c.	Distribution - Maintenance [3]	=	277,154
d.	Administrative and General [3]	=	277,154
e.	Depreciation [3]	=	277,154
f.	Interest [3]	=	277,154
g.	Margin Requirements [3]	=	277,152
h.	Subtotal		1,662,922
i.	Total -- Expenses		3,238,051

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1 From Exhibit__(DEA-1), page 16.
2 From See Exhibit__(DEA-1), page 25.
3 Includes both Controlled Off-Peak Energy Storage (51) and Interruptible Heating Service (52).
4 Split remainder of revenue approximately equal between Distribution Operation and Maintenance, Administration and General, Depreciation and Interest.

Classification of Revenue Requirements

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Power Supply**																
2		**Production**																
3	500-557	Fuel	FUEL															
4	500-557	Non-Fuel O&M - Demand	PROD1															
5	500-557	Non-Fuel O&M - Energy	PROD1															
6		Subtotal - Production																
7		**Purchases**																
8	555	Direct Assign. Chgs (Cr.)																
9	555	Substation Charges	SUB															
10	555	Demand Charges	PURKW-1															
11	555	Summer	PURKW-2	17,112,830		17,885,414												
12	555	Winter	PURKW-3	8,390,047		8,390,047												
13	555	Other	PURKW-4	8,011,190		8,011,190												
14	555	Energy Charges - Critical Peak	PURKWH-1															
15	555	Energy Charges - On-Peak	PURKWH-2	36,393,097	36,393,097													
16	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550	56,517,550													
17	555	Standby Reservation Fee	REV															
18		Subtotal - Purchases		126,424,714	92,910,647	34,286,651												
19	500-557	Total Power Supply		126,424,714	92,910,647	34,286,651												
20																		
21		**Transmission**																
22	560-573	Operation & Maintenance	TRAN1															
23	555	Transmission - G&T Charges	TRAN2	22,649,623				22,649,623										
24		Total Transmission		22,649,623				22,649,623										
25																		
26		**Distribution**																
27	580	Oper. Super & Eng.	EX1															
28	581	Load Dispatch	EX1	1,410,722					265,542		227,970	98,059				819,151		
29	582	Oper. Station	SUB	631,828					631,828									
30	583	Oper. OH Line	PRI-OH	21,432							3,767	17,665						
31	584	Oper. UG Line	PRI-UG	703,799							529,785	174,014						
32	585	Oper. St. Lighting	STL															
33	586	Oper. Meters	MTR	1,949,081												1,949,081		
34	587	Oper. Cons. Install	ICON	50,520							8,879	41,642						
35	588	Oper. Misc. Oper.	EX1	1,849,603					348,153		298,892	128,565				1,073,992		
36	589	Rents	EX1															
37	590	Main. Super. & Eng.	EX2	4,204,506					371,258		667,009	3,128,264	7,481	30,493				
38	591	Main. Structure	SUB															
39	592	Main. Station	SUB	125,460					125,460									
40	593	Main. OH Line	PRI-OH	1,282,541							225,403	1,057,138						
41	594	Main. UG Line	PRI-UG															
42	595	Main. Line Transf.	TRF	12,832									2,528	10,304				
43	596	Main. St. Lighting	STL	491,419														
44	597	Main. Meters	MTR															
45	598	Main. Misc. Dist.	EX2															
46	580-598	Subtotal		12,733,743					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224		

Classification of Revenue Requirements

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
1		**Power Supply**								
2		**Production**								
3	500-557	Fuel	FUEL							
4	500-557	Non-Fuel O&M - Demand	PROD1							
5	500-557	Non-Fuel O&M - Energy	PROD1							
6		Subtotal - Production								
7		**Purchases**								
8	555	Direct Assign. Chgs (Cr.)								
9	555	Substation Charges	SUB							
10	555	Demand Charges	PURKW-1							
11	555	Summer	PURKW-2	17,112,830	(725,733)	(46,851)				
12	555	Winter	PURKW-3	8,390,047						
13	555	Other	PURKW-4	8,011,190						
14	555	Energy Charges - Critical Peak	PURKWH-1							
15	555	Energy Charges - On-Peak	PURKWH-2	36,393,097						
16	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550						
17	555	Standby Reservation Fee	REV							
18		Subtotal - Purchases		126,424,714	(725,733)	(46,851)				
19	500-557	Total Power Supply		126,424,714	(725,733)	(46,851)				
20										
21		**Transmission**								
22	560-573	Operation & Maintenance	TRAN1							
23	555	Transmission - G&T Charges	TRAN2	22,649,623						
24		Total Transmission		22,649,623						
25										
26		**Distribution**								
27	580	Oper. Super & Eng.	EX1							
28	581	Load Dispatch	EX1	1,410,722						
29	582	Oper. Station	SUB	631,828						
30	583	Oper. OH Line	PRI-OH	21,432						
31	584	Oper. UG Line	PRI-UG	703,799						
32	585	Oper. St. Lighting	STL							
33	586	Oper. Meters	MTR	1,949,081						
34	587	Oper. Cons. Install	ICON	50,520						
35	588	Oper. Misc. Oper.	EX1	1,849,603						
36	589	Rents	EX1							
37	590	Main. Super. & Eng.	EX2	4,204,506						
38	591	Main. Structure	SUB							
39	592	Main. Station	SUB	125,460						
40	593	Main. OH Line	PRI-OH	1,282,541						
41	594	Main. UG Line	PRI-UG							
42	595	Main. Line Transf.	TRF	12,832						
43	596	Main. St. Lighting	STL	491,419						491,419
44	597	Main. Meters	MTR							
45	598	Main. Misc. Dist.	EX2							
46	580-598	Subtotal		12,733,743						491,419

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
47		**Consumer Acct., Service & Sales**																
48		**Consumer Accounting**																
49	901	Supervision	CACC															
50	902	Meter Reading Expense	CACC	935,425													935,425	
51	903	Records & Collections	CACC	4,358,650													4,358,650	
52	904	Uncollectible Accounts	CACC	399,734													399,734	
53	905	Misc. Customer Account	CACC															
54		Subtotal		5,693,809													5,693,809	
55																		
56		**Consumer Service & Info.**																
57	907	Supervision	CS															
58	908	Customer Assistance	CS	2,247,863													2,247,863	
59	909	Info. & Instruction	CS	875,663													875,663	
60	910	Misc. Cust Serv. & Info	CS	281,773													281,773	
61		Subtotal		3,405,299													3,405,299	
62																		
63		**Sales**																
64	911	Supervision	SALES															
65	912	Demonstrating & Selling	SALES															
66	913	Advertising	SALES															
67	916	Misc. Sales	SALES															
68		Subtotal																
69																		
70		**Prorated Operating Expenses**																
71	920-	**Administrative & General**																
72	932	Power Supply	EX6-PS	1,170,247	860,025	317,373												
73		Transmission	EX6-TR															
74		Distribution	EX6-D	10,532,220					840,462		946,332	2,240,927	4,828	19,681		1,853,498	4,389,432	
75		Subtotal - A&G		11,702,467	860,025	317,373			840,462		946,332	2,240,927	4,828	19,681		1,853,498	4,389,432	
76																		
77	408	**Other Taxes**																
78		Power Supply	EX6-PS															
79		Transmission	EX6-TR															
80		Distribution	EX6-D															
81		Subtotal - Other Taxes																
82																		
83	421-	**Miscellaneous Expense**																
84	426,431	Power Supply	EX6-PS	51,654	37,961	14,009												
85		Transmission	EX6-TR															
86		Distribution	EX6-D	464,888					37,098		41,771	98,914	213	869		81,813	193,748	
87		Subtotal - Misc. Expense		516,542	37,961	14,009			37,098		41,771	98,914	213	869		81,813	193,748	

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
47		**Consumer Acct., Service & Sales**								
48		**Consumer Accounting**								
49	901	Supervision	CACC							
50	902	Meter Reading Expense	CACC	935,425						
51	903	Records & Collections	CACC	4,358,650						
52	904	Uncollectible Accounts	CACC	399,734						
53	905	Misc. Customer Account	CACC							
54		Subtotal		5,693,809						
55										
56		**Consumer Service & Info.**								
57	907	Supervision	CS							
58	908	Customer Assistance	CS	2,247,863						
59	909	Info. & Instruction	CS	875,663						
60	910	Misc. Cust Serv. & Info	CS	281,773						
61		Subtotal		3,405,299						
62										
63		**Sales**								
64	911	Supervision	SALES							
65	912	Demonstrating & Selling	SALES							
66	913	Advertising	SALES							
67	916	Misc. Sales	SALES							
68		Subtotal								
69										
70		**Prorated Operating Expenses**								
71	920-	**Administrative & General**								
72	932	Power Supply	EX6-PS	1,170,247	(6,718)	(434)				
73		Transmission	EX6-TR							
74		Distribution	EX6-D	10,532,220						237,062
75		Subtotal - A&G		11,702,467	(6,718)	(434)				237,062
76										
77	408	**Other Taxes**								
78		Power Supply	EX6-PS							
79		Transmission	EX6-TR							
80		Distribution	EX6-D							
81		Subtotal - Other Taxes								
82										
83	421-	**Miscellaneous Expense**								
84	426,431	Power Supply	EX6-PS	51,654	(297)	(19)				
85		Transmission	EX6-TR							
86		Distribution	EX6-D	464,888						10,464
87		Subtotal - Misc. Expense		516,542	(297)	(19)				10,464

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
88		**Fixed Charges**																
89	403-	**Depreciation**																
90	407	Power Supply	PROPLNT															
91		Transmission	TRNPLNT															
92		Distribution	DSTPLNT	10,408,894					1,516,978		4,657,498	2,519,423	226,938	925,038	78,444	177,014		
93		Subtotal - Depreciation		10,408,894					1,516,978		4,657,498	2,519,423	226,938	925,038	78,444	177,014		
94																		
95	408	**Property Taxes**																
96		Power Supply	PROPLNT															
97		Transmission	TRNPLNT															
98		Distribution	DSTPLNT	3,550,790					517,487		1,588,814	859,452	77,416	315,559	26,760	60,385		
99		Subtotal - Property Taxes		3,550,790					517,487		1,588,814	859,452	77,416	315,559	26,760	60,385		
100																		
101	427	**Interest-LT**																
102		Power Supply	PROPLNT															
103		Transmission	TRNPLNT															
104		Distribution	DSTPLNT	3,489,324					508,529		1,561,311	844,574	76,075	310,096	26,297	59,340		
105		Subtotal - Interest-LT		3,489,324					508,529		1,561,311	844,574	76,075	310,096	26,297	59,340		
106																		
107		**Required Margin**																
108		Power Supply	PROPLNT															
109		Transmission	TRNPLNT															
110		Distribution	DSTPLNT	6,495,238					946,607		2,906,318	1,572,142	141,611	577,231	48,950	110,458		
111		Subtotal - Required Margin		6,495,238					946,607		2,906,318	1,572,142	141,611	577,231	48,950	110,458		
112																		
113		**Summary of Revenue Requirements**																
114		Power Supply		127,646,615	93,808,633	34,618,033												
115		Transmission		22,649,623				22,649,623										
116		Distribution		56,774,205					6,109,403		13,663,749	12,780,779	537,091	2,189,270	180,451	6,184,731	13,682,287	
117		**Total Revenue Required**		207,070,443	93,808,633	34,618,033		22,649,623	6,109,403		13,663,749	12,780,779	537,091	2,189,270	180,451	6,184,731	13,682,287	

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
88		**Fixed Charges**								
89	403-	**Depreciation**								
90	407	Power Supply	PROPLNT							
91		Transmission	TRNPLNT							
92		Distribution	DSTPLNT	10,408,894						307,560
93		Subtotal - Depreciation		10,408,894						307,560
94										
95	408	**Property Taxes**								
96		Power Supply	PROPLNT							
97		Transmission	TRNPLNT							
98		Distribution	DSTPLNT	3,550,790						104,918
99		Subtotal - Property Taxes		3,550,790						104,918
100										
101	427	**Interest-LT**								
102		Power Supply	PROPLNT							
103		Transmission	TRNPLNT							
104		Distribution	DSTPLNT	3,489,324						103,102
105		Subtotal - Interest-LT		3,489,324						103,102
106										
107		**Required Margin**								
108		Power Supply	PROPLNT							
109		Transmission	TRNPLNT							
110		Distribution	DSTPLNT	6,495,238						191,920
111		Subtotal - Required Margin		6,495,238						191,920
112										
113		**Summary of Revenue Requirements**								
114		Power Supply		127,646,615	(732,748)	(47,303)				
115		Transmission		22,649,623						
116		Distribution		56,774,205						1,446,444
117		**Total Revenue Required**		207,070,443	(732,748)	(47,303)				1,446,444

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
		Classification Factor Data																
1	PROPLNT	Production Plant	Plant															
2	TRNPLNT	Transmission Plant	Plant															
3	DSTPLNT	Distribution Plant	Plant	157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,356,660					631,828		542,430	233,321				1,949,081		
6	EX2	Assigned Dist. Main. Exp.	Rev Req	1,420,834					125,460		225,403	1,057,138	2,528	10,304				
7	EX3	Dist. Oper. & Main.	Rev Req	12,733,743					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224		
8	EX4	Assigned O & M Exp.	Rev Req	170,907,188	92,910,647	34,286,651		22,649,623	1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224	9,099,108	
9	EX4-PS	Power Supply	Rev Req	126,424,714	92,910,647	34,286,651												
10	EX4-TR	Transmission	Rev Req	22,649,623				22,649,623										
11	EX4-D	Distribution	Rev Req	21,832,851					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224	9,099,108	
12	EX5	Rev. Req. Less Margin	Rev Req	200,575,205	93,808,633	34,618,033		22,649,623	5,162,796		10,757,431	11,208,637	395,479	1,612,039	131,501	6,074,272	13,682,287	
13	EX5-PS	Power Supply	Rev Req	127,646,615	93,808,633	34,618,033												
14	EX5-TR	Transmission	Rev Req	22,649,623				22,649,623										
15	EX5-D	Distribution	Rev Req	50,278,967					5,162,796		10,757,431	11,208,637	395,479	1,612,039	131,501	6,074,272	13,682,287	

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
		Classification Factor Data								
1	PROPLNT	Production Plant	Plant							
2	TRNPLNT	Transmission Plant	Plant							
3	DSTPLNT	Distribution Plant	Plant	157,954,781						4,667,216
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	157,954,781						4,667,216
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,356,660						
6	EX2	Assigned Dist. Main. Exp.	Rev Req	1,420,834						
7	EX3	Dist. Oper. & Main.	Rev Req	12,733,743						491,419
8	EX4	Assigned O & M Exp.	Rev Req	170,907,188	(725,733)	(46,851)				491,419
9	EX4-PS	Power Supply	Rev Req	126,424,714	(725,733)	(46,851)				
10	EX4-TR	Transmission	Rev Req	22,649,623						
11	EX4-D	Distribution	Rev Req	21,832,851						491,419
12	EX5	Rev. Req. Less Margin	Rev Req	200,575,205	(732,748)	(47,303)				1,254,524
13	EX5-PS	Power Supply	Rev Req	127,646,615	(732,748)	(47,303)				
14	EX5-TR	Transmission	Rev Req	22,649,623						
15	EX5-D	Distribution	Rev Req	50,278,967						1,254,524

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
16	**Classification Factors**																	
17	CACC	Consumer Accounting	Input	1.000000													1.000000	
18	CS	Customer Service	Input	1.000000													1.000000	
19	CS-PS	Cust. Service - Pwr. Supply	Input															
20	CS-TR	Cust. Service - Transmission	Input															
21	CS-D	Cust. Service - Distribution	Input															
22	SALES	Sales	Input															
23	SALES-PS	Sales - Power Supply	Input															
24	SALES-TR	Sales - Transmission	Input															
25	SALES-D	Sales - Distribution	Input															
26	PROPLNT	Production Plant	Plant															
27	TRNPLNT	Transmission Plant	Plant															
28	DSTPLNT	Distribution Plant	Plant	1.000000					0.145739		0.447454	0.242045	0.021802	0.088870	0.007536	0.017006		
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000					0.145739		0.447454	0.242045	0.021802	0.088870	0.007536	0.017006		
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000					0.188231		0.161598	0.069510				0.580661		
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000					0.088300		0.158642	0.744027	0.001779	0.007252				
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000					0.136821		0.154056	0.364806	0.000786	0.003204		0.301736		
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	0.543632	0.200616		0.132526	0.010194		0.011478	0.027181	0.000059	0.000239		0.022481	0.053240	
34	EX4-PS	Power Supply	Rev Req	0.739727	0.543632	0.200616												
35	EX4-TR	Transmission	Rev Req	0.132526				0.132526										
36	EX4-D	Distribution	Rev Req	0.127747					0.010194		0.011478	0.027181	0.000059	0.000239		0.022481	0.053240	
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	0.467698	0.172594		0.112923	0.025740		0.053633	0.055882	0.001972	0.008037	0.000656	0.030284	0.068215	
38	EX5-PS	Power Supply	Rev Req	0.636403	0.467698	0.172594												
39	EX5-TR	Transmission	Rev Req	0.112923				0.112923										
40	EX5-D	Distribution	Rev Req	0.250674					0.025740		0.053633	0.055882	0.001972	0.008037	0.000656	0.030284	0.068215	
41	EX6	A&G Classification	Input	1.000000	0.073491	0.027120			0.071819		0.080866	0.191492	0.000413	0.001682		0.158385	0.375086	
42	EX6-PS	Power Supply	Input	0.100000	0.073491	0.027120												
43	EX6-TR	Transmission	Input															
44	EX6-D	Distribution	Input	0.900000					0.071819		0.080866	0.191492	0.000413	0.001682		0.158385	0.375086	
45	FUEL	Fuel	Input															
46	ICON	Install Cons. Prem.	Input	1.000000							0.175747	0.824253						
47	LAND	Land & Land Rights	Input	1.000000					1.00000									
48	LICON	Leased Property	Input	1.000000							0.175747	0.824253						
49	MTR	Meters	Input	1.000000												1.000000		
50	POLES	Poles, Towers, and Fixtures	1.0000								0.439954	0.560046						
51	PRI-OH	Primary Line-Overhead	Input	1.000000							0.175747	0.824253						
52	PRI-UG	Primary Line-Underground	1.0000								0.752750	0.247250						
53	PROD1	Production Plant	Input															
54	PROD2	Production O & M	Input															
55	PURTR-1	Trans. Capacity	Input	1.000000				1.000000										
56	PURTR-2	Trans. Energy	Input	1.000000	1.000000													
57	PURKW-1	Purchased Power Capacity	Input	1.000000		1.000000												
58	PURKW-2	Summer	Input	1.000000		1.000000												
59	PURKW-3	Winter	Input	1.000000		1.000000												
60	PURKW-4	Other	Input	1.000000		1.000000												
61	PURKWH-1	Purchased Power Energy	Input	1.000000	1.000000													
62	PURKWH-2	On-Peak	Input	1.000000	1.000000													
63	PURKWH-3	Off-Peak	Input	1.000000	1.000000													
62	SERV	Services	Input	1.000000											1.000000			
63	STL	Street Lighting	Input															
64	SUB	Substation	Input	1.000000					1.000000									
65	TRAN1	Transmission Plant	Input	1.000000				1.000000										
66	TRAN2	Transmission Purchases	Input	1.000000				1.000000										
67	TRF	Line Transf.	Input	1.000000									0.196999	0.803001				

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
16	**Classification Factors**									
17	CACC	Consumer Accounting	Input	1.000000						
18	CS	Customer Service	Input	1.000000						
19	CS-PS	Cust. Service - Pwr. Supply	Input							
20	CS-TR	Cust. Service - Transmission	Input							
21	CS-D	Cust. Service - Distribution	Input							
22	SALES	Sales	Input							
23	SALES-PS	Sales - Power Supply	Input							
24	SALES-TR	Sales - Transmission	Input							
25	SALES-D	Sales - Distribution	Input							
26	PROPLNT	Production Plant	Plant							
27	TRNPLNT	Transmission Plant	Plant							
28	DSTPLNT	Distribution Plant	Plant	1.000000						0.029548
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000						0.029548
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000						
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000						
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000						0.038592
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	(0.004246)	(0.000274)				0.002875
34	EX4-PS	Power Supply	Rev Req	0.739727	(0.004246)	(0.000274)				
35	EX4-TR	Transmission	Rev Req	0.132526						
36	EX4-D	Distribution	Rev Req	0.127747						0.002875
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	(0.003653)	(0.000236)				0.006255
38	EX5-PS	Power Supply	Rev Req	0.636403	(0.003653)	(0.000236)				
39	EX5-TR	Transmission	Rev Req	0.112923						
40	EX5-D	Distribution	Rev Req	0.250674						0.006255
41	EX6	A&G Classification	Input	1.000000	(0.000574)	(0.000037)				0.020257
42	EX6-PS	Power Supply	Input	0.100000	(0.000574)	(0.000037)				
43	EX6-TR	Transmission	Input							
44	EX6-D	Distribution	Input	0.900000						0.020257
45	FUEL	Fuel	Input							
46	ICON	Install Cons. Prem.	Input	1.000000						
47	LAND	Land & Land Rights	Input	1.000000						
48	LICON	Leased Property	Input	1.000000						
49	MTR	Meters	Input	1.000000						
50	POLES	Poles, Towers, and Fixtures	1.0000							
51	PRI-OH	Primary Line-Overhead	Input	1.000000						
52	PRI-UG	Primary Line-Underground	1.0000							
53	PROD1	Production Plant	Input							
54	PROD2	Production O & M	Input							
55	PURTR-1	Trans. Capacity	Input	1.000000						
56	PURTR-2	Trans. Energy	Input	1.000000						
57	PURKW-1	Purchased Power Capacity	Input	1.000000						
58	PURKW-2	Summer	Input	1.000000						
59	PURKW-3	Winter	Input	1.000000						
60	PURKW-4	Other	Input	1.000000						
61	PURKWH-1	Purchased Power Energy	Input	1.000000						
62	PURKWH-2	On-Peak	Input	1.000000						
63	PURKWH-3	Off-Peak	Input	1.000000						
62	SERV	Services	Input	1.000000						
63	STL	Street Lighting	Input							
64	SUB	Substation	Input	1.000000						
65	TRAN1	Transmission Plant	Input	1.000000						
66	TRAN2	Transmission Purchases	Input	1.000000						
67	TRF	Line Transf.	Input	1.000000						

Summary of Allocation of Revenue Requirements to Rate Classes

Line No.	Cost Classification		Alloc. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Power Supply**									
2	**Wholesale Power**									
3	Direct Assigned Charges (Credits)		Direct							
4	Demand Related		D7							
5	Demand Related - Summer		D4	17,112,830	10,370,341	464,867	21,695	6,179,315	76,613	
6	Demand Related - Winter		D5	8,390,047	5,458,423	302,784		2,488,808	36,721	103,311
7	Demand Related - Other		D6	8,011,190	4,952,367	264,721	3,164	2,702,767	36,516	51,656
8	Subtotal - Demand			33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
9	Energy Charges - Critical Peak		E2							
10	Energy Related - On-Peak		E3	36,393,097	17,333,391	879,140	164,592	9,570,234	8,407,488	38,252
11	Energy Related - Off-Peak		E4	56,517,550	26,723,916	1,355,423	253,762	14,754,997	12,962,322	467,130
12	Subtotal - Energy			92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
13	Revenue Related		R2							
14	Subtotal - Wholesale			126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
15	**Allocated Overhead & Margin**									
16	Direct Related		Direct							
17	Revenue Related		R2							
18	Demand Related		D7	328,991	198,146	10,188	183	105,776	12,878	1,819
19	Energy Related		E1	892,910	420,872	21,278	4,042	235,006	206,454	5,257
20	Subtotal - Allocated			1,221,901	619,019	31,466	4,225	340,782	219,332	7,076
21	Subtotal - Power Supply			127,646,615	65,457,456	3,298,400	447,438	36,036,904	21,738,992	667,425
22										
23	**Transmission**									
24	Direct Assigned		Direct							
25	Demand Related		D7	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
26	Energy Related		E1							
27	Subtotal--Transmission			22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
28	**Allocated Overhead & Margin**									
29	Direct Related		Direct							
30	Revenue Related		R2							
31	Demand Related		D7							
32	Energy Related		E1							
33	Subtotal - Allocated									
34	Subtotal - Transmission			22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
35										
36	**Distribution**									
37	Power Supply	-Energy	E1							
38	Dist. Sub.	-Capacity	D9	6,109,403	3,010,588	149,743	47,121	1,598,656	1,263,802	39,493
39	Dist. Sub.	-Consumer	C2							
40	Primary Line	-Capacity	D9	13,663,749	6,733,215	334,901	105,386	3,575,413	2,826,507	88,326
41	Primary Line	-Consumer	C2	12,780,779	11,552,938	610,737	67,936	463,412	47,096	38,660
42	Line Transf.	-Capacity	D1	537,091	369,821	16,955	10,460	87,871	50,629	1,355
43	Line Transf.	-Consumer	C3	2,189,270	1,946,450	115,497	14,312	96,436	10,063	6,513
44	Sec. & Serv.	-Consumer	C4	180,451	165,079	7,965	798	5,512	544	552
45	Meter	-Consumer	C5	6,184,731	5,150,000	311,923	58,073	449,082	198,419	17,234
46	Acct. & Serv.	-Consumer	C6	13,682,287	11,393,185	690,057	128,473	993,491	438,957	38,125
47	Revenue Related	-Revenue	R2							
48	Direct Assigned		Direct	1,446,444						1,446,444
49	Subtotal - Distribution			56,774,205	40,321,277	2,237,776	432,558	7,269,873	4,836,017	1,676,703
50	**Total**			207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Allocation of Net Plant in Service To Rate Classes

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1		**Net Intangible Plant**								
2	301	Organization	PLNT							
3	302	Franchises and consents	PLNT							
4	303	Miscellaneous intangible plant	PLNT							
5	301-303	Subtotal	PLNT							
6										
7		**Net Production Plant**								
8	310-346	Production Plant	PROD1							
9										
10		**Net Transmission Plant**								
11	350-359	Transmission Plant	TRAN1							
12										
13		**Net Distribution Plant**								
14	360	Land	LAND	4,163,712	2,517,895	129,805	2,300	1,329,041	161,813	22,858
15	361	Structures	SUB							
16	362	Station	SUB	18,856,408	11,402,915	587,852	10,416	6,018,896	732,812	103,517
17	363	Battery	SUB							
18	364	Poles, towers	PRI	10,796,888	7,806,614	405,374	68,778	1,462,221	1,004,903	48,997
19	365	OH Cond	PRI	13,738,437	11,425,872	600,301	78,815	1,042,393	541,194	49,861
20	366	UG Conduit	PRI							
21	367	UG Cond	PRI	84,374,330	50,155,173	2,553,592	600,753	17,375,897	13,215,247	473,668
22	368	Transf	TRF	17,481,215	14,851,750	849,266	158,835	1,181,760	389,152	50,453
23	369	Services	SERV	1,190,394	1,088,990	52,546	5,261	36,362	3,591	3,644
24	370	Meters	MTR	2,686,182	2,236,773	135,476	25,222	195,048	86,178	7,485
25	371	Cons Premise	ICON	123,745						123,745
26	372	Leased Prop	LICON							
27	373	St. Light	STL	4,543,471						4,543,471
28	360-373	Subtotal		157,954,781	101,485,981	5,314,211	950,381	28,641,619	16,134,891	5,427,699
29										
30		**Net General Plant**								
31	389	Land & Land Rights	PLNT	102,278	65,714	3,441	615	18,546	10,448	3,515
32	390	Structures and Improve.	PLNT	4,601,923	2,956,737	154,827	27,689	834,457	470,081	158,133
33	391	Office Furniture & Equip.	PLNT	5,056,678	3,248,917	170,126	30,425	916,917	516,534	173,759
34	392	Transportation & Equipment	PLNT	918,591	590,195	30,905	5,527	166,566	93,833	31,565
35	393	Stores Equipment	PLNT	18,982	12,196	639	114	3,442	1,939	652
36	394	Tool, Shop & Garage Equip.	PLNT	156,304	100,425	5,259	940	28,342	15,966	5,371
37	395	Laboratory Equipment	PLNT	209,246	134,441	7,040	1,259	37,942	21,374	7,190
38	396	Power Operated Equipment	PLNT	3,930,565	2,525,389	132,239	23,649	712,721	401,502	135,063
39	397	Communication Equipment	PLNT	345,799	222,176	11,634	2,081	62,703	35,323	11,882
40	398	Miscellaneous Equipment	PLNT	84,672	54,402	2,849	509	15,353	8,649	2,910
41	399	Other tangible property	PLNT	633,349	406,927	21,308	3,811	114,844	64,696	21,763
42	389-399	Subtotal		16,058,389	10,317,518	540,266	96,620	2,911,835	1,640,345	551,804
43										
44		**Total Net Plant in Service**		174,013,170	111,803,499	5,854,477	1,047,001	31,553,453	17,775,236	5,979,503

Allocation of Revenue Requirements to Rate Classes

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1		**Power Supply**								
2		**Production**								
3	500-557	Fuel	FUEL							
4	500-557	Non-Fuel O&M - Demand	PROD1							
5	500-557	Non-Fuel O&M - Energy	PROD1							
6		Subtotal - Production								
7		**Purchases**								
8	555	Direct Assign. Chgs (Cr.)								
9	555	Substation Charges	PURSUB							
10	555	Demand Charges	PURKW-1							
11	555	Summer	PURKW-2	17,112,830	10,370,341	464,867	21,695	6,179,315	76,613	
12	555	Winter	PURKW-3	8,390,047	5,458,423	302,784		2,488,808	36,721	103,311
13	555	Other	PURKW-4	8,011,190	4,952,367	264,721	3,164	2,702,767	36,516	51,656
14		Total Demand		33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
15	555	Energy Charges - Critical Peak	PURKWH-1							
16	555	Energy Charges - On-Peak	PURKWH-2	36,393,097	17,333,391	879,140	164,592	9,570,234	8,407,488	38,252
17	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550	26,723,916	1,355,423	253,762	14,754,997	12,962,322	467,130
18		Total Energy		92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
19	555	Standby Reservation Fee	REVENUE							
20		Subtotal - Purchases		126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
21	500-557	Total Power Supply		126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
22		**Transmission**								
23	560-573	Operation & Maintenance	TRAN1							
24	555	Transmission - G&T Charges	TRAN2	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
25		Total Transmission		22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
26		**Distribution**								
27	580	Oper. Super & Eng.	EX1							
28	581	Load Dispatch	EX1	1,410,722	1,013,935	58,095	12,019	192,173	128,730	5,769
29	582	Oper. Station	SUB	631,828	311,352	15,486	4,873	165,331	130,701	4,084
30	583	Oper. OH Line	PRI-OH	21,432	17,824	936	123	1,626	844	78
31	584	Oper. UG Line	PRI-UG	703,799	418,364	21,300	5,011	144,939	110,233	3,951
32	585	Oper. St. Lighting	STL							
33	586	Oper. Meters	MTR	1,949,081	1,622,992	98,301	18,301	141,526	62,531	5,431
34	587	Oper. Cons. Install	ICON	50,520	42,016	2,207	290	3,833	1,990	183
35	588	Oper. Misc. Oper.	EX1	1,849,603	1,329,374	76,169	15,758	251,959	168,779	7,564
36	589	Rents	EX1							
37	590	Main. Super. & Eng.	EX2	4,204,506	3,371,633	176,779	24,981	387,678	227,151	16,284
38	591	Main. Structure	SUB							
39	592	Main. Station	SUB	125,460	61,824	3,075	968	32,829	25,953	811
40	593	Main. OH Line	PRI-OH	1,282,541	1,066,654	56,041	7,358	97,312	50,523	4,655
41	594	Main. UG Line	PRI-UG							
42	595	Main. Line Transf.	TRF	12,832	10,902	623	117	867	286	37
43	596	Main. St. Lighting	STL	491,419						491,419
44	597	Main. Meters	MTR							
45	598	Main. Misc. Dist.	EX2							
46	580-598	Subtotal		12,733,743	9,266,869	509,013	89,799	1,420,075	907,720	540,267

Allocation of Revenue Requirements to Rate Classes
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
47		**Consumer Acct., Service & Sales**								
48		**Consumer Accounting**								
49	901	Supervision	CACC							
50	902	Meter Reading Expense	CACC	935,425	778,924	47,177	8,783	67,923	30,010	2,607
51	903	Records & Collections	CACC	4,358,650	3,629,430	219,825	40,926	316,488	139,835	12,145
52	904	Uncollectible Accounts	CACC	399,734	332,857	20,160	3,753	29,025	12,824	1,114
53	905	Misc. Customer Account	CACC							
54		Subtotal		5,693,809	4,741,212	287,163	53,463	413,436	182,669	15,866
55		**Consumer Service & Info.**								
56	907	Supervision	CS							
57	908	Customer Assistance	CS	2,247,863	1,871,787	113,369	21,107	163,221	72,116	6,264
58	909	Info. & Instruction	CS	875,663	729,161	44,163	8,222	63,583	28,093	2,440
59	910	Misc. Cust Serv. & Info	CS	281,773	234,631	14,211	2,646	20,460	9,040	785
60		Subtotal		3,405,299	2,835,579	171,744	31,975	247,264	109,249	9,489
61		**Sales**								
62	911	Supervision	SALES							
63	912	Demonstrating & Selling	SALES							
64	913	Advertising	SALES							
65	916	Misc. Sales	SALES							
66		Subtotal								
67		**Prorated Operating Expenses**								
68		**Administrative & General**								
69	920	Administrative & General		6,994,984						
70	921	Office Supplies & Expenses		1,400,794						
71	922	Admin. Expenses Transferred								
72	923	Outside Services Employed		468,099						
73	924	Property Insurance		72,601						
74	925	Injuries & Damages		3,441						
75	926	Employee Pensions & Benefits		1,665,361						
76	927	Franchise Requirements								
77	928	Regulatory Commission Exp.		419,597						
78	929	Duplicate Charges								
79	930.1	General Advertising								
80	930.2	Misc.		677,590						
81	931	Rents								
82	935	Maint. of General Plant								
83		Accounts 920-935		11,702,467						
84		Power Supply	EX6-PS	1,170,247	592,851	30,136	4,046	326,376	210,061	6,777
85		Transmission	EX6-TR							
86		Distribution	EX6-D	10,532,220	8,125,422	466,927	84,535	1,003,771	578,709	272,857
87		Subtotal - A&G		11,702,467	8,718,273	497,063	88,581	1,330,147	788,769	279,634

Allocation of Revenue Requirements to Rate Classes
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
88	408	**Other Taxes**								
89		Power Supply	EX6-PS							
90		Transmission	EX6-TR							
91		Distribution	EX6-D							
92		Subtotal - Other Taxes								
93	421-	**Miscellaneous Expense**								
94	426,431	Power Supply	EX6-PS	51,654	26,168	1,330	179	14,406	9,272	299
95		Transmission	EX6-TR							
96		Distribution	EX6-D	464,888	358,653	20,610	3,731	44,306	25,544	12,044
97		Subtotal - Misc. Expense		516,542	384,821	21,940	3,910	58,712	34,816	12,343
98		**Fixed Charges**								
99	403-	**Depreciation**								
100	407	Power Supply	PROPLNT							
101		Transmission	TRNPLNT							
102		Distribution	DSTPLNT	10,408,894	6,517,900	340,085	73,490	1,800,160	1,318,107	359,153
103		Subtotal - Depreciation		10,408,894	6,517,900	340,085	73,490	1,800,160	1,318,107	359,153
104	408	**Property Taxes**								
105		Power Supply	PROPLNT							
106		Transmission	TRNPLNT							
107		Distribution	DSTPLNT	3,550,790	2,223,454	116,013	25,070	614,089	449,646	122,518
108		Subtotal - Property Taxes		3,550,790	2,223,454	116,013	25,070	614,089	449,646	122,518
109										
110		Total Oper. Expenses		174,436,258	99,526,544	5,209,956	809,501	41,580,003	25,310,637	1,999,617
111										
112	427	**Interest-LT**								
113		Power Supply	PROPLNT							
114		Transmission	TRNPLNT							
115		Distribution	DSTPLNT	3,489,324	2,184,965	114,005	24,636	603,459	441,863	120,397
116		Subtotal - Interest-LT		3,489,324	2,184,965	114,005	24,636	603,459	441,863	120,397
117		**Required Margin**								
118		Power Supply	PROPLNT							
119		Transmission	TRNPLNT							
120		Distribution	DSTPLNT	6,495,238	4,067,225	212,216	45,859	1,123,315	822,510	224,114
121		Subtotal - Required Margin		6,495,238	4,067,225	212,216	45,859	1,123,315	822,510	224,114
122		**Summary of Revenue Requirements**								
123		Total Rev. Req.		207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Rate Class Weighting Factors

I. Three Phase Vs. Single Phase Class Weighting Factors

A. Investment to Serve 3Ø vs. 1Ø Consumers (use replacement cost)

1. Meters	1Ø		3Ø		Wtd.
a. Resid.& Farm	$88.39	100%		0%	$88.39
b. Small General Service	$88.39	65%	$181.86	35%	$121.10
c. Irrigation	$191.86	10%	$261.86	90%	$254.86
d. General Service		18%	$341.86	82%	$280.33
e. C&I Interruptible		0%	$1,302.86	100%	$1,302.86
2 Service [1]	$481		$694		
3. Transformer [2]	$1,718		$2,751		
4. Primary Line [3]	$1,151		$1,787		

B. Weighting Factors for Relative 3Ø Class Investment Costs

1. Meters					
a. Resid.& Farm	$88	÷	$88	=	1.00
b. Small General Service	$121	÷	$88	=	1.37
c. Irrigation	$255	÷	$88	=	2.88
d. General Service	$280	÷	$88	=	3.17
e. C&I Interruptible	$1,303	÷	$88	=	14.74
2 Service	$2,330	÷	$1,847	=	1.26
3. Transformer	$8,582	÷	$4,339	=	1.98
4. Primary Line	$6,393	÷	$4,099	=	1.56

[1] Assume a typical installation of 80 feet of 1/0 triplex (or quadriplex), pole and miscellaneous materials to estimate the difference between a 1Ø and 3Ø installation.

[2] Use the cost difference between 1-75 kVA transformer and 3-25 kVA transformers as representative of the difference between a 1Ø versus a 3Ø transformer installation.

[3] Assume a typical installation of 150 feet of 1/0 ACSR to estimate the difference in primary line between a 1Ø and 3Ø installation.

Analysis of Class Load Characteristics

Line No.	Description	Units	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Class Billing Determinants**								
2	No. of Cons.	cons.	124,847	100,235	4,431	392	2,756	262	16,771
3	Energy Sales -- All	MWh	1,769,404	838,684	42,538	7,964	463,060	406,800	10,359
4	Energy Sales -- On-Peak	MWh	591,321	281,636	14,284	2,674	155,499	136,606	622
5	Energy Sales -- Off-Peak	MWh	1,178,083	557,048	28,253	5,290	307,561	270,194	9,737
6	Billing Demand	kW-mo.	2,496,047			76,255	1,449,303	970,490	
7									
8	**Demand Estimate**								
9	Non-Coincidental Demand of								
10	Individual Cons.	kW	1,122,260.0	772,748	35,427	21,856	183,608	105,789	2,832
11	Non-Coincidental Class Demand	kW	387,770.7	201,097	9,755	4,702	101,451	67,934	2,832
12	Coincidental Summer Demand	kW	326,853.1	202,779	9,352	396	112,926	1,400	
13	Coincidental Winter Demand	kW	229,990.6	149,628	8,300		68,224	1,007	2,832
14	Coincidental Other Demand	kW	219,605.0	135,756	7,257	87	74,089	1,001	1,416
15	Coincidental Class Demand-Transm.	kW	257,935.3	155,980	8,041	142	82,332	10,024	1,416
16	Base Rated Substation Capacity	kVA	632,500.0						

Estimate of Class Demands

I. Residential & Farm (31,32,53)

A. Demand Per Consumer Calculation

	Summer [1]	Winter [1]	Other [1]	Avg.
Energy usage/Month (kWh/cons/mo)	900	727	643	722
Estimated fully diversified demand per consumer (kW/cons.) [2]	2.44	2.02	1.81	2.01

B. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

"A" Factor [3] = $(1 - 0.4 + 0.4 (1^2 + 40)$^1/2) = 3.1612

Total kW = 100,235 Cons. x 3.1612 x 2.44 = 772,748

C. Non-Coincidental Class Demand (Average Monthly)

"A" Factor [3] = $(1 - (0.4 \times 100{,}235) + 0.4(100{,}235^2 + 40)$^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.01 = 201,097

D. Non-Coincidental Class Demand (Summer)

"A" Factor [3] = $(1 - (0.4 \times 100{,}235) + 0.4(100{,}235^2 + 40)$^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.44 = 244,463

E. Non-Coincidental Class Demand (Winter)

(1 - "A" Factor [3] = $(1 - (0.4 \times 100{,}235) + 0.4(100{,}235^2 + 40)$^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.02 = 202,394

---

[1] GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

[2] The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

[3] The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{½})$$

Estimate of Class Demands
(Continued)

I. Residential & Farm (31,32,53) (Continued)

F. Non-Coincidental Class Demand (Other)

"A" Factor [3]	=	$(1 - (0.4 \times 100{,}235) + 0.4(100{,}235^2 + 40)^{\wedge}1/2)$							=	1.0001
Total kW	=	100,235	Cons.	x	1.0001	x	1.81		=	181,664

G. Assigned Coincidental Demand Responsibility -- Summer

kW = 202,779 [4]

H. Assigned Coincidental Demand Responsibility -- Winter

kW = 149,628 [4]

I. Assigned Coincidental Demand Responsibility -- Other

kW = 135,756 [4]

J. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 155,980 [4]

---

1 GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

2 The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

3 The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{½})$$

4 See pages 39 and 40.

Estimate of Class Demands
(Continued)

II. Small General Service (41)

A. Demand Per Consumer Calculation

	Summer [1]	Winter [1]	Other [1]	Avg.
Energy usage/Month (kWh/cons/mo)	852	938	783	800
Estimated fully diversified demand per consumer (kW/cons.) [2]	2.32	2.53	2.16	2.20

B. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

"A" Factor [3]	=	(1 - 0.4 + 0.4 (1² + 40)^1/2)					=	3.1612
Total kW	=	4,431	Cons.	x	3.1612	x 2.53	=	35,427

C. Non-Coincidental Class Demand (Average Monthly)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)					=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x 2.20	=	9,755

D. Non-Coincidental Class Demand (Summer)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)					=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x 2.32	=	10,319

E. Non-Coincidental Class Demand (Winter)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)					=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x 2.53	=	11,227

---

1 GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

2 The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

3 The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{½})$$

Estimate of Class Demands
(Continued)

II. Small General Service (41) (Continued)

F. Non-Coincidental Class Demand (Other)

"A" Factor [3]	=	$(1 - (0.4 \times 4{,}431) + 0.4(4{,}431^2 + 40)^{1/2})$							=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x	2.16		=	9,566

G. Assigned Coincidental Demand Responsibility -- Summer

kW = 9,352 [4]

H. Assigned Coincidental Demand Responsibility -- Winter

kW = 8,300 [4]

I. Assigned Coincidental Demand Responsibility -- Other

kW = 7,257 [4]

J. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 8,041 [4]

---

1 GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

2 The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

3 The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{1/2})$$

4 See pages 39 and 40.

Estimate of Class Demands
(Continued)

III. Irrigation (36)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

21,856 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 76,255 kW.

2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:

   7,963,872 kWh/(76,255 kW x 730 hr.) = 14.3%

3. The coincidence factor is estimated from Bary curves to be 74%.

4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:

   (76,255 kW / 12 mo.) x 0.74 = 4,702 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 15,828 kW.

2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:

   2,312,050 kWh/(15,828 kW x 730 hr.) = 20.0%

3. The coincidence factor is estimated from Bary curves to be 79%.

4. The non-coincidental (system basis) summer demand of the class is estimated to be:

   15,828 kW x 0.79 = 12,504 kW

Estimate of Class Demands
(Continued)

III. Irrigation (36) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 159 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   11,999 kWh/(159 kW x 730 hr.) = 0.0%

3. The coincidence factor is estimated from Bary curves to be 0%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   159 kW x 0.00 = 0 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the other months non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 4,716 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   165,287 kWh/(4,716 kW x 730 hr.) = 4.8%

3. The coincidence factor is estimated from Bary curves to be 58%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   4,716 kW x 0.58 = 2,735 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 396 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 0 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 87 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 142 [1]

[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

IV. General Service (46)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

183,608 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 1,449,303 kW.

2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:
   463,059,984 kWh/(1,449,303 kW x 730 hr.) = 43.8%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:
   (1,449,303 kW / 12 mo.) x 0.84 = 101,451 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 139,671 kW.

2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:
   50,334,827 kWh/(139,671 kW x 730 hr.) = 49.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) summer demand of the class is estimated to be:
   139,671 kW x 0.84 = 117,323 kW

Estimate of Class Demands
(Continued)

IV. General Service (46) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 109,861 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   42,032,747 kWh/(109,861 kW x 730 hr.) = 52.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   109,861 kW x 0.84 = 92,283 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the Other non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 116,785 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   39,942,113 kWh/(116,785 kW x 730 hr.) = 46.9%

3. The coincidence factor is estimated from Bary curves to be 83%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   116,785 kW x 0.83 = 96,931 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 112,926 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 68,224 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 74,089 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 82,332 [1]

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[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

V. General Service Peak Alert (70,71)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

105,789 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 970,490 kW.
2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:
   406,800,000 kWh/(970,490 kW x 730 hr.) = 57.4%
3. The coincidence factor is estimated from Bary curves to be 84%.
4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:
   (970,490 kW / 12 mo.) x 0.84 = 67,934 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 93,162 kW.
2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:
   38,279,750 kWh/(93,162 kW x 730 hr.) = 56.3%
3. The coincidence factor is estimated from Bary curves to be 84%.
4. The non-coincidental (system basis) summer demand of the class is estimated to be:
   93,162 kW x 0.84 = 78,256 kW

Estimate of Class Demands
(Continued)

V. General Service Peak Alert (70,71) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 68,418 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   31,189,530 kWh/(68,418 kW x 730 hr.) = 62.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   68,418 kW x 0.84 = 57,471 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the Other non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 80,958 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   33,065,360 kWh/(80,958 kW x 730 hr.) = 55.9%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   80,958 kW x 0.84 = 68,005 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 1,400 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 1,007 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 1,001 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 1,102 [1]

---

[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

	Power Required Per Light			No. of	
Size & Type	**Lamp**	**Ballast**	**Total**	**Lights**	**Total**
	(kW)	(kW)	(kW)		(kW)
Security Lighting (Schedule 44)					
175 W MV	0.175	0.035	0.210	0	0
100 W HPS	0.100	0.035	0.135	819	111
150 W HPS	0.150	0.050	0.200	4	1
250 W HPS	0.250	0.060	0.310	8	2
				831	114
Street Lighting (Schedule 44-2))					
(DEA Owned Equipment)					
175 W MV	0.175	0.035	0.210	0	0
250 W MV	0.250	0.050	0.300	3	1
400 W MV	0.400	0.050	0.450	0	0
100 W HPS	0.100	0.035	0.135	38	5
150 W HPS	0.150	0.050	0.200	646	129
250 W HPS	0.250	0.060	0.310	1,597	495
400 W HPS	0.400	0.075	0.475	1	0
				2,285	631
Street Lighting (Schedule 44-1)					
(Cons. Owned Equipment)					
175 W MV	0.175	0.035	0.210	0	0
250 W MV	0.250	0.050	0.300	0	0
400 W MV	0.400	0.050	0.450	0	0
100 W HPS	0.100	0.035	0.135	0	0
150 W HPS	0.150	0.050	0.200	101	20
200 W HPS	0.200	0.055	0.255	101	26
250 W HPS	0.250	0.060	0.310	272	84
400 W HPS	0.400	0.075	0.475	13	6
				487	136
Custom Resid. Lighting(Schedule 44-3)					
(DEA Owned contrib. by Cons.)					
175 W MV	0.175	0.035	0.210	0	0
50 W HPS	0.050	0.020	0.070	81	6
100 W HPS	0.100	0.035	0.135	8,416	1,136
150 W HPS	0.150	0.050	0.200	3,732	746
250 W HPS	0.250	0.060	0.310	4	1
				12,233	1,889
LED Security Lighting (44-4)					
LED, >4,500 Lumens			0.048	338	16

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting (Continued)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

Size & Type	Power Required Per Light: Lamp	Ballast	Total	No. of Lights	Total
LED Street Lighting Member Owned(44-5)					
A (40-80 watts)			0.060	0	0
B (81-150 watts)			0.115	0	0
C (151-250 watts)			0.200	11	2
D (251-350 watts)			0.300	0	0
E (351-450 watts)			0.400	0	0
				11	2
LED Street Lighting (44-6)					
Standard					
>5,200 L, Coach (Post)			0.075	121	9
>5,200 L, Acorn (Post)			0.060	48	3
>7,000 L, Cobra (Mast)			0.066	91	6
>11,500 L, Shoebox			0.109	151	16
Basic					
>5,200 L, Coach (Post)			0.075	41	3
>5,200 L, Acorn (Post)			0.060	0	0
>7,000 L, Cobra (Mast)			0.066	53	3
>11,500 L, Shoebox			0.109	16	2
				521	43

The sum of the non-coincidental demands of individual lights is estimated as: 2,832 kW

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting

B. Non-Coincidental Class Demand (Average Monthly)

1. The non-coincidental (system basis) class demand for the average month is assumed equal to the undiversified peak annual demand of 2,832 kW calculated above.

C. Assigned Coincidental Demand Responsibility -- Summer

kW = 0 [1]

D. Assigned Coincidental Demand Responsibility -- Winter

kW = 2,832 [1]

E. Assigned Coincidental Demand Responsibility -- Other

kW = 1,416 [1]

F. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 1,416 [1]

[1] See pages 39 and 40.

Dakota Electric

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

A. Non-Coincidental Class Demands	Summer (kW)	Winter (kW)	Other (kW)
Residential & Farm (31,32,53)	174,147	202,394	169,945
Residential & Farm Controlled A/C (8131)	70,316	0	11,719
Small General Service (41)	9,064	11,227	9,357
Small General Service Controlled A/C (8141)	1,255	0	209
Irrigation (36)	12,504	0	2,735
General Service (46)	117,323	92,283	96,931
General Service Peak Alert (70,71)	78,256	57,471	68,005
Street and Security Lighting	2,832	2,832	2,832
Total	465,697	366,207	361,734

B. Coincidence Factors (Summer)	Summer (kW)	Winter (kW)	Other (kW)
1. Other Classes			
Coincidence Factor			
Summer Coincidental Demand	326,853	229,990	219,605
Less:			
Residential & Farm Controlled A/C (8131)	35,158		5,860
Small General Service Controlled A/C (8141)	628		105
Irrigation (36)	396	0	87
General Service Peak Alert (70,71)	1,400	1,007	1,001
Street and Security Lighting	0	2,832	1,416
Total	289,271	226,152	211,137
Summer Non-Coincidental Demand	465,697		361,734
Less:			
Residential & Farm Controlled A/C (8131)	70,316	366,207	11,719
Small General Service Controlled A/C (8141)	1,255		209
Irrigation (36)	12,504	0	2,735
General Service Peak Alert (70,71)	78,256	57,471	68,005
Street and Security Lighting	2,832	2,832	2,832
Total	300,534	305,904	276,233
Coincidence Factor =	289,271	226,152	211,137
	300,534	305,904	276,233
=	96.25%	73.93%	76.43%

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

C. Assigned Coincidental Demand Responsibility (Summer Peak)

Rate Class	Summer Non-Coinc. Demand (kW)	Coinc. Factor	Summer Coinc. Demand (kW)	
Residential & Farm (31,32,53)	174,147	0.9625	167,621	
Plus: Controlled A/C	70,316	0.5000	35,158	
Total Residential & Farm (31,32,53)	244,463	0.8295	202,779	
Small General Service (41)	9,064	0.9625	8,724	
Less Controlled A/C	1,255	0.5000	628	
Total Small General Service (41)	10,319	0.9063	9,352	
Irrigation (36)	12,504	0.0317	396	1
General Service (46)	117,323	0.9625	112,926	
General Service Peak Alert (70,71)	78,256	0.0179	1,400	
Street and Security Lighting	2,832	0.0000	0	
Total	465,697		326,853	

D. Assigned Coincidental Demand Responsibility (Winter Peak)

Rate Class	Winter Non-Coinc. Demand (kW)	Coinc. Factor	Winter Coinc. Demand (kW)
Residential & Farm (31,32,53)	202,394	0.7393	149,628
Small General Service (41)	11,227	0.7393	8,300
Irrigation (36)	0	0.0000	0
General Service (46)	92,283	0.7393	68,224
General Service Peak Alert (70,71)	57,471	0.0240	1,007
Street and Security Lighting	2,832	1.0000	2,832
Total	366,207		229,990

1 Approximately 95.8% of the irrigation load is controlled so that it does not add to the GRE coincidental peak. Assume 75% coincident factor for the remaining customers.

Summer	0.042 x 12,504 kW x 0.75	396	kW (CD)	=	396
Other	0.042 x 2,735 kW x 0.75	87	kW (CD)	=	87

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

E. Assigned Coincidental Demand Responsibility (Other Peak)

Rate Class	Other Non-Coinc. Demand (kW)	Coinc. Factor	Other Coinc. Demand (kW)
Residential & Farm (31,32,53)	169,945	0.7643	129,896
Less Controlled A/C	11,719	0.5000	5,860
Net Residential & Farm (31,32,53)	181,664	0.7473	135,756
Small General Service (41)	9,357	0.7643	7,152
Less Controlled A/C	209	0.5000	105
Net Small General Service (41)	9,566	0.7586	7,257
Irrigation (36)	2,735	0.0317	87
General Service (46)	96,931	0.7643	74,089
General Service Peak Alert (70,71)	68,005	0.0320	1,001
Street and Security Lighting	2,832	0.5000	1,416
Total	361,734		219,605

F. Assigned Coincidental Demand Responsibility
(25% Summer, 25% Winter, 50% Other months)

	Ave. Coinc. Demand (kW)	Transm. & Anc. (kW)
Residential & Farm (31,32,53)	155,980	155,980
Small General Service (41)	8,041	8,041
Irrigation (36)	142	142
General Service (42)	82,332	82,332
General Service Peak Alert (70)	1,102	10,024
Street and Security Lighting	1,416	1,416
Total	249,013	257,935

General Service Peak Alert (70)		Class NCP	CF	Monthly Transm.	Annual Transm.
Summer	3 mos.	78,256	0.0179	1,400	4,200
Winter	3 mos.	57,471	0.2000	11,494	34,483
Other	6 mos.	68,005	0.2000	13,601	81,606
					120,289
					12
					10,024

Development of Allocation Factors

Line No.	Description	Units	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Allocation Factor Input Data**								
2	**Energy**								
3	Energy Sales -- All	MWh	1,769,404	838,684	42,538	7,964	463,060	406,800	10,359
4	Energy Sales -- Critical Peak	MWh							
5	Energy Sales -- On-Peak	MWh	591,321	281,636	14,284	2,674	155,499	136,606	622
6	Energy Sales -- Off-Peak	MWh	1,178,083	557,048	28,253	5,290	307,561	270,194	9,737
7	Dist. Losses	MWh	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%
8	Energy -- All @ Sub.	MWh	1,816,837	861,167	43,678	8,177	475,474	417,705	10,636
9	Energy -- Critical Peak @ Sub.	MWh							
10	Energy -- On-Peak @ Sub.	MWh	607,173	289,186	14,667	2,746	159,667	140,268	638
11	Energy -- Off-Peak @ Sub.	MWh	1,209,664	571,981	29,011	5,431	315,806	277,437	9,998
12	Trans. Losses	MWh							
13	Energy -- All @ Source	MWh	1,816,837	861,167	43,678	8,177	475,474	417,705	10,636
14	Energy -- Critical Peak @ Source	MWh							
15	Energy -- On-Peak @ Source	MWh	607,173	289,186	14,667	2,746	159,667	140,268	638
16	Energy -- Off-Peak @ Source	MWh	1,209,664	571,981	29,011	5,431	315,806	277,437	9,998
17	**Demand**								
18	Non-Coin. Demand @ Cons.	kW	1,122,260	772,748	35,427	21,856	183,608	105,789	2,832
19	Class Non-Coin. Demand @ Sub.	kW	387,771	201,097	9,755	4,702	101,451	67,934	2,832
20	Class Non-Coin. Demand Transm.	kW	387,771	201,097	9,755	4,702	101,451	67,934	2,832
21	Summer Coin. Demand	kW	326,853	202,779	9,352	396	112,926	1,400	
22	Winter Coin. Demand	kW	229,991	149,628	8,300		68,224	1,007	2,832
23	Other Coin. Demand	kW	219,605	135,756	7,257	87	74,089	1,001	1,416
24	Trans. Coin. Demand	kW	257,935	155,980	8,041	142	82,332	10,024	1,416
25									
26	**Average and Excess Demand**								
27	Average Demand	kW	207,402	98,307	4,986	933	54,278	47,683	1,214
28	Class Excess Demand	kW	180,369	102,790	4,769	3,769	47,173	20,251	1,618
29	Alloc. Excess Demand	kW	50,534	28,799	1,336	1,056	13,217	5,674	453
30	Avg. & Excess Demand	kW	257,935	127,105	6,322	1,989	67,494	53,357	1,667
31	**Revenue**								
32	Present Rate Revenue	$	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
33	Proposed Rate Revenue	$	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
34	**Consumer**								
35	No. Consumers		124,847	100,235	4,431	392	2,756	262	16,771
36	Pri. Line Weight. Factor			1.00	1.20	1.50	1.46	1.56	0.02
37	Weight. No. of Cons.		110,887.9	100,235.0	5,298.8	589.4	4,020.6	408.6	335.4
38	Transf. Weight. Factor			1.00	1.34	1.88	1.80	1.98	0.02
39	Weight. No. of Cons.		112,739.4	100,235.0	5,947.6	737.0	4,966.1	518.2	335.4
40	Service Weight. Factor			1.00	1.09	1.24	1.21	1.26	0.02
41	Weight. No. of Cons.		109,568.6	100,235.0	4,836.5	484.3	3,346.9	330.5	335.4
42	Meter Weight. Factor			1.00	1.37	2.88	3.17	14.74	0.02
43	Weight. No. of Cons.		120,374.1	100,235.0	6,071.0	1,130.3	8,740.5	3,861.9	335.4
44	Cons. Acct. Weight Factor			1.00	1.37	2.88	3.17	14.74	0.02
45	Weight. No. of Cons.		120,374.1	100,235.0	6,071.0	1,130.3	8,740.5	3,861.9	335.4

Development of Allocation Factors
(Continued)

Line No.	Description	Data Line No.	Name	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
46	**Allocation Factors**									
47	**Energy Related**									
48	Energy -- All @ Sub.	8	E1	1.000000	0.473992	0.024041	0.004501	0.261704	0.229908	0.005854
49	Energy -- Critical Peak @ Sub.	9	E2							
50	Energy -- On-Peak @ Sub.	10	E3	1.000000	0.476282	0.024157	0.004523	0.262968	0.231019	0.001051
51	Energy -- Off-Peak @ Sub.	11	E4	1.000000	0.472843	0.023982	0.004490	0.261069	0.229350	0.008265
52	Energy -- All @ Source	13	E5	1.000000	0.473992	0.024041	0.004501	0.261704	0.229908	0.005854
53	Energy -- Critical Peak @ Source	14	E6							
54	Energy -- On-Peak @ Source	15	E7	1.000000	0.476282	0.024157	0.004523	0.262968	0.231019	0.001051
55	Energy -- Off-Peak @ Source	16	E8	1.000000	0.472843	0.023982	0.004490	0.261069	0.229350	0.008265
56										
57	**Demand Related**									
58	Non-coin. Demand @ Cons.	18	D1	1.000000	0.688564	0.031567	0.019475	0.163606	0.094265	0.002523
59	Non-coin. Demand @ Class	19	D2	1.000000	0.518597	0.025156	0.012127	0.261627	0.175192	0.007303
60	Non-coin. Demand @ Transm	20	D3	1.000000	0.518597	0.025156	0.012127	0.261627	0.175192	0.007303
61	Summer Coin. Demand	21	D4	1.000000	0.620398	0.028611	0.001213	0.345495	0.004284	
62	Winter Coin. Demand	22	D5	1.000000	0.650583	0.036088		0.296638	0.004377	0.012314
63	Other Coin. Demand	23	D6	1.000000	0.618181	0.033044	0.000395	0.337374	0.004558	0.006448
64	Trans. Coin. Demand @ Sub.	24	D7	1.000000	0.604724	0.031175	0.000552	0.319196	0.038863	0.005490
65	Coin. Demand @ Source	25	D8							
66	Avg. & Excess	30	D9	1.000000	0.492779	0.024510	0.007713	0.261671	0.206862	0.006464
67										
68	**Revenue Related**									
69	Present Rate Revenue	32	R1	1.000000	0.572277	0.028904	0.004625	0.255463	0.128246	0.010486
70	Proposed Rate Revenue	33	R2	1.000000	0.572277	0.028904	0.004625	0.255463	0.128246	0.010486
71										
72	**Consumer Related**									
73	No. of Cons.	35	C1	1.000000	0.802863	0.035491	0.003140	0.022075	0.002099	0.134332
74	Pri. Line Weight. Cons.	37	C2	1.000000	0.903931	0.047786	0.005315	0.036259	0.003685	0.003025
75	Transf. Weight. Cons.	39	C3	1.000000	0.889086	0.052756	0.006537	0.044049	0.004597	0.002975
76	Services Weight. Cons.	41	C4	1.000000	0.914815	0.044141	0.004420	0.030546	0.003016	0.003061
77	Meter Weight. Cons.	43	C5	1.000000	0.832696	0.050434	0.009390	0.072611	0.032082	0.002786
78	Cons. Acct. Weight. Cons.	45	C6	1.000000	0.832696	0.050434	0.009390	0.072611	0.032082	0.002786

Docket No. E-111/GR-19-478

Exhibit__(DEA-2)
Determination of Revenue Requirements

**Determination of Revenue
Requirements - Summary**

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Present Rates Pro Forma Test Year	(e) Proposed Rates Pro Forma Test Year
	Financial Results From Rates	($)	($)	($)
1	Total Revenue [1]	203,138,675	201,581,098	210,263,272
2	Operating Expense [1]	197,774,614	199,769,626	199,769,626
3	Net Operating Income (before interest expense) [2]	5,364,061	1,811,472	10,493,646
4	Capital Credits [3]	5,111,212	5,111,212	5,111,212
5	Other Non-Operating Income [3]	292,978	292,978	292,978
6	Total Margin (before interest expense) [4]	10,768,251	7,215,662	15,897,836
	Required Increase (Decrease) --ROR Objective			
7	Operating Expense (excluding interest) [1]	197,774,614	199,769,626	199,769,626
8	Margin Requirements			
9	Rate Base [5]	189,064,856	189,064,856	189,064,856
10	Rate of Return [6]	5.73%	5.73%	5.73%
11	Required Return [7]	10,831,846	10,831,846	10,831,846
12	Less: Non-Operating Income [3]	292,978	292,978	292,978
13	Net Operating Income Required [8]	10,538,868	10,538,868	10,538,868
14	Total Revenue Requirements [9]	208,313,482	210,308,494	210,308,494
15	Revenue Present Rates			
16	Tariff Revenue [1]	202,630,477	200,480,307	209,128,484
17	Other Operating Revenue [1]	508,198	1,100,791	1,134,788
18	Total Revenue [10]	203,138,675	201,581,098	210,263,272
19	Required Increase (Decrease) [11]	5,174,807	8,727,396	45,222
20	Percent Increase (Decrease) [12]	2.55	4.35	0.02

[1] See Exhibit__(DEA-1).
[2] Line 1 minus Line 2.
[3] See Workpaper 1.
[4] Line 3 plus Line 4 plus Line 5.
[5] See Exhibit__(DEA-2), page 2.
[6] See Exhibit__(DEA-2), page 8.
[7] Line 9 times Line 10.
[8] Line 11 minus Line 12.
[9] Line 7 plus Line 13.
[10] Line 16 plus Line 17.
[11] Line 14 minus Line 18.
[12] Line 19 divided by Line 16.

Rate Base

(a) Line No.	(b) Description	(c) Proposed Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	300,342,133
2	Construction Work in Progress [1]	4,222,209
3	Less: Accumulated Provision for Deprec. [2]	126,526,023
4	Net Plant [1]	178,038,319
5	Materials & Supplies - Electric [3]	4,715,491
6	Working Capital [4]	6,816,147
7	Subtotal	11,531,638
8	Less: Consumer Deposits [1]	505,101
9	**Total Rate Base**	189,064,856

1 December 31, 2018 Form 7 amount. See Workpaper 1.

2 December 31, 2018 Form 7 amount adjusted to include Depreciation adjustment .
See Exhibit _ (DEA-1), page x.

3 Thirteen - month average. See Exhibit__(DEA-2), page 3.

Rate Base Calculations
Materials & Supplies

(a) Line No.	(b) Month		(c) Materials & Supplies Electric [1]
			($)
1	Dec	2017	4,472,686
2	Jan	2018	4,649,607
3	Feb	2018	4,676,986
4	Mar	2018	4,753,122
5	Apr	2018	4,953,466
6	May	2018	5,128,406
7	Jun	2018	4,907,896
8	Jul	2018	5,020,268
9	Aug	2018	4,854,970
10	Sep	2018	4,612,252
11	Oct	2018	4,752,223
12	Nov	2018	4,335,261
13	Dec	2018	4,184,242
14	**Total**		61,301,385
15	**13 - Month Average**		4,715,491

[1] Inventory accounts 13110 through 13320 from December 31, 2018 year end General Ledger.

Cost of Debt

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Target Debt	(g) Cost of Debt	(h) Weighted Cost of Debt
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	CFC	3.400%	1,585,363	53,902			
2	CFC	4.500%	2,082,541	93,714			
3	CFC	4.050%	1,766,030	71,524			
4	CFC	4.250%	2,218,947	94,305			
5	CFC	3.500%	2,465,360	86,288			
6	CFC	3.800%	3,794,320	144,184			
7	CFC	3.550%	11,379,844	403,984			
8	CFC	3.550%	4,704,028	166,993			
9	CFC	3.750%	4,337,267	162,648			
10	CFC	3.300%	1,917,161	63,266			
11	CFC	2.500%	1,309,090	32,727			
12	CFC	3.600%	4,705,933	169,414			
13	CFC	3.750%	9,749,608	365,610			
14	CFC	4.250%	9,957,793	423,206			
15	CFC/Farmer Mac	4.250%	2,816,884	119,718			
16	CFC/Farmer Mac	3.830%	1,632,746	62,534			
17	CFC/Farmer Mac	3.970%	992,292	39,394			
18	CoBank	4.350%	1,059,986	46,109			
19	CoBank	2.590%	3,841,338	99,491			
20	CoBank	4.101%	4,904,209	201,122			
21	CoBank	3.500%	1,088,704	38,105			
22	CoBank	4.560%	4,332,287	197,552			
23	CoBank	3.950%	3,433,732	135,632			
24	CoBank	3.960%	3,738,278	148,036			
25	CoBank	1.910%	167,115	3,192			
26	CoBank	2.760%	1,546,883	42,694			
27	CoBank	3.960%	3,745,754	148,332			
28	CoBank	3.340%	4,574,903	152,802			
	Total Long Term Debt 12/31/2018[2]		99,848,397	3,766,478	60%	3.77%	2.26%

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.
[2] Equals Form 7, Part C, Line 38 (Long Term Debt) plus Line 45 (Current Portion) 93,460,696 + 6,387,701 = 99,848,397

Historic Total Capitalization

(a) Line No.	(b) Year	(c) Equity	(d) Debt	(e) Total Capitalization [1]
				($)
1	1998	47,724,259	89,235,673	136,959,932
2	1999	47,523,140	86,467,753	133,990,893
3	2000	48,277,127	86,508,221	134,785,348
4	2001	52,338,198	84,148,127	136,486,325
5	2002	56,192,068	91,885,042	148,077,110
6	2003	59,702,313	92,300,874	152,003,187
7	2004	60,411,502	104,332,408	164,743,910
8	2005	69,656,348	100,360,082	170,016,430
9	2006	81,417,061	101,287,278	182,704,339
10	2007	89,428,738	107,146,528	196,575,266
11	2008	94,900,838	107,846,291	202,747,129
12	2009	100,631,181	114,660,602	215,291,783
13	2010	109,245,168	115,021,054	224,266,222
14	2011	119,055,182	112,770,620	231,825,802
15	2012	127,764,369	98,368,388	226,132,757
16	2013	136,837,360	92,752,617	229,589,977
17	2014	147,409,115	96,605,051	244,014,166
18	2015	150,975,647	94,984,079	245,959,726
19	2016	161,294,191	93,878,841	255,173,032
20	2017	169,199,058	97,068,697	266,267,755
21	2018	173,151,167	99,848,397	272,999,564

The mean growth rate in Total Capitalization is estimated to be:

2013 - 2018 = 3.52%

Total Capitalization figures represent Margins & Equities plus Total Long-Term Debt for the years listed. See Workpaper 1 for years 2014 thru 2018.

Asset Growth Rate
Department of Commerce Methodology
(Natural Logarithm of a Number)

(a) *LN of* ***Assets***	(b) ***Year***	(c) ***Time***	(d) ***Assets*** [1]	(e) From LRF
19.6450	2018	1	340,193,777	340,193,777
19.6618	2019	2	345,961,418	345,961,418
19.6816	2020	3	352,873,712	352,873,712
19.6974	2021	4	358,477,813	358,477,813
19.7135	2022	5	364,321,717	364,321,717
19.7318	2023	6	371,018,880	371,018,880
19.7445	2024	7	375,785,642	375,785,642
19.7583	2025	8	380,994,230	380,994,230
19.7713	2026	9	385,996,186	385,996,186
19.7851	2027	10	391,362,529	391,362,529
19.8009	2028	11	397,573,959	397,573,959

0.0154 (10 yr. exponential GR)
0.0173 (5 yr. exponential GR)

1 Assets represent forecasted Assets for the years listed.
See Workpaper 5, Page 2.

Ratio Calculations
Department of Commerce Methodology

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Year	***Equity*** [1]	***Debt*** [2]	***Total Capital*** [3]	***Equity Ratio*** [4]	***Debt Ratio*** [5]	***Assets*** [6]	***Equity as % of Assets*** [7]
2019	175,914,526	105,640,524	281,555,050	0.6248	0.3752	345,961,418	50.85%
2020	177,214,989	111,540,354	288,755,343	0.6137	0.3863	352,873,712	50.22%
2021	178,231,219	116,416,226	294,647,445	0.6049	0.3951	358,477,813	49.72%
2022	179,402,896	121,376,453	300,779,349	0.5965	0.4035	364,321,717	49.24%
2023	180,280,744	127,483,768	307,764,512	0.5858	0.4142	371,018,880	48.59%
2024	179,749,233	133,070,041	312,819,274	0.5746	0.4254	375,785,642	47.83%
2025	179,718,738	138,597,124	318,315,862	0.5646	0.4354	380,994,230	47.17%
2026	178,123,694	145,364,127	323,487,821	0.5506	0.4494	385,996,186	46.15%
2027	176,747,430	152,394,734	329,142,164	0.5370	0.4630	391,362,529	45.16%
2028	176,124,124	159,517,470	335,641,594	0.5247	0.4753	397,573,959	44.30%
			5-yr average:	60.51%	39.49%		49.72%
			10-yr average:	57.77%	42.23%		47.92%

[1] See Workpaper 5
[2] See Workpaper 5
[3] Column b plus Column c
[4] Column b divided by Column d
[5] 1 minus Column e
[6] See Workpaper 5
[7] Column b divided by Column g

Overall Return on Rate Base
Department of Commerce Methodology

Assumptions:

1	Asset Growth Rate	1.73%
2	Equity Ratio	53.085%
3	Debt Ratio	46.915%
4	Test Year Total Capital	$ 272,999,564
5	Test Year Total Equity	$ 173,151,167
6	Test Year Total Debt	$ 99,848,397
7	Annual Capital Credits	$ 3,500,000
8	Rate Base	$ 189,064,856
9	Cost of Long-Term Debt	3.77%

Terms:

CC	Capital Credits
DR	Debt Ratio = (Debt/Total Capital)
ER	Equity Ratio = (Equity/Total Capital)
g	Growth in Equity
i	Cost of Long-Term Debt
K	Rate of Return on Equity
OCC	Overall Cost of Capital
RB	Rate Base
ROR	Return on Rate Base
TC	Total Capital
TIER	Times Interest Earned Ratio

DOC Method:

	g	ER	TC	CC
Return on Equity: K=g+(CC/(ER x TC))	0.0173	0.5309	272,999,564	$ 3,500,000

Return on Equity:	0.0414	K = g + (CC/(ER x TC))
Overall Cost of Capital (OCC):	0.0397	OCC = (ER x K) + ((1 - ER) x i)
Overall Return on Rate Base:	**0.0573**	ROR = OCC x (TC/RB)
Times Interest Earned Ratio:	2.24	TIER = ((K x ER) + (i x DR)) / (i x DR)

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1 5 Year Asset Growth Rate, See Exhibit__(DEA-2), Page 6
2 Average of 2022 and 2023 Equity Ratios, See Exhibit__(DEA-2), Page 7
3 1 - (Equity/Total Capital)
4 See DEA Exhibit_(DEA-2), Page 5
5 See DEA Exhibit_(DEA-2), Page 5
6 See DEA Exhibit_(DEA-2), Page 5
7 DEA Board Resolution 14-5-5 Long Range Financial Forecast
8
9 See DEA Exhibit_(DEA-2), Page 4

Docket No. E-111/GR-19-478

Exhibit __(DEA-1)
Statement of Operations -
Present Rates

Statement of Operations
Present Rates
Test Year - 2018 Historical Adjusted

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Adjustments [1]	(e) Pro Forma Test Year	
1	**Operating Revenue**	($)	($)	($)	
2	Rate Schedules	202,630,477	(2,150,170)	200,480,307	[2]
3	Other	508,198	592,593	1,100,791	
4	**Total Operating Revenue**	203,138,675	(1,557,577)	201,581,098	
5	**Operating Expenses**				
6	Cost of Purchased Power	149,330,034	1,319,432	150,649,466	[3]
7	Transmission - O & M	-		-	
8	Distribution - Operation	7,277,184	(383,045)	6,894,139	
9	Distribution - Maintenance	6,151,338	242,574	6,393,912	
10	Consumer Accounts	5,312,955	380,854	5,693,809	
11	Consumer Service & Information	3,585,760	(180,461)	3,405,299	
12	Sales	-		-	
13	Administrative & General	11,907,838	71,783	11,979,621	
14	Depreciation & Amortization	10,281,975	404,073	10,686,048	
15	Taxes - Property	3,372,283	178,507	3,550,790	
16	Taxes - Other	-		-	
17	Other Interest Expense	549,008		549,008	
18	Other Deductions	6,239	(38,705)	(32,466)	
19	**Total Operating Expenses** (Before Long Term Interest)	197,774,614	1,995,012	199,769,626	
20	**Net Operating Income** (Before Long Term Interest)	5,364,061	(3,552,589)	1,811,472	

[1] The operating expense adjustments are summarized on pages 2 through 10.
[2] See pages 12 through 21 for Pro Forma Test Year Revenue.
[3] See page 22 for Pro Forma Test Year Purchased Power expense.

Summary of Test Year Adjustments to Operating Expenses

(a) Line No.	(b) Description		(c) 2018 Actual		(d) Adjustments		(e) Pro Forma Test Year	Change from 2018 Actual
	Operating Expenses							
1	Distribution - Operation (DO)	$	7,277,184	$	(383,045)	$	6,894,139	-5.3%
2	Distribution - Maintenance (DM)		6,151,338		242,574		6,393,912	3.9%
3	Consumer Accounts (CA)		5,312,955		380,854		5,693,809	7.2%
4	Consumer Service & Information (CS)		3,585,760		(180,461)		3,405,299	-5.0%
5	Sales				-		-	
6	Administrative & General (AG)		11,907,838		71,783		11,979,621	0.6%
7	Depreciation & Amortization		10,281,975		404,073		10,686,048	3.9%
8	Taxes - Property		3,372,283		178,507		3,550,790	5.3%
9	Taxes - Other		-		-		-	
10	Other Interest Expense		549,008		-		549,008	0.0%
11	Other Deductions		6,239		(38,705)		(32,466)	-620.4%
12	**Total Operating Expenses Excluding Purchased Power** (Before Long Term Interest)	$	48,444,580	$	675,580	$	49,120,160	1.4%
	Check Total							

Summary of Test Year Adjustments to Operating Expenses			Reference
Payroll			
General Payroll Increase	$	420,048	Page 3 of 22
Capital to Expense Changes		(65,168)	Page 4 of 22
Staffing Changes		260,379	Page 5 of 22
Total Payroll Adjustments		615,259	
Payroll Benefits			
Benefits on General Payroll Increase		197,171	Page 7 of 22
Benefits on Capital to Expense Changes		(30,590)	Page 7 of 22
Benefits on Staffing Changes		122,222	Page 7 of 22
Base Benefit Decrease		(393,317)	Page 6 of 22
Total Payroll Benefits		(104,514)	
Depreciation		404,073	Page 8 of 22
Other Adjustments		(118,505)	Page 10 of 22
Property Taxes		178,507	Page 8 of 22
Reduction in CIP Spending 2019 Budget to 2018 Actual		(200,296)	Page 9 of 22
Regulatory Filing Fees		18,800	Page 9 of 22
Rate Filing Fees recovery over 5 years		82,000	Page 10 of 22
Net Deduction for Disallowed Expenses		(199,744)	Page 10 of 22
Total Test Year Adjustments	$	675,580	

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL

GENERAL WAGE INCREASE

	Effective Date	Avg. % Increase	Wages Booked Prior To Increase	Wages Booked After Increase
			($)	($)
Union (Hourly Wages & OT)			Expensed	Expensed
Historical Test Year	1/1/18	2.50%	-	7,047,334
				Jan thru Dec
Future Test Year	1/1/19	2.50%	-	7,223,518
Non-Union (Salaries, PT, etc.)				
Historical Test Year	6/1/18	2.50%	3,745,930	5,462,416
			Jan thru Jun	Jul - Dec
Future Test Year	6/1/19	2.75%	3,839,578	5,612,632
Net Adjustment to Expensed Wages				**420,048**
Total Union & Non-Union			**Salaries & Wages Only**	**Total Comp inc OT, PT, etc.**
Historical			15,133,222	16,255,680
Future Test Year			15,524,462	16,675,728
Net Increase			2.6%	2.6%

Is the increase shown for the Future Test Year committed or still to be negotiated?

Union: Committed

Non-Union: Not Committed

CAPITAL TO EXPENSE CHANGE FOR NORMALIZED CONSTRUCTION YEAR

	% Expensed		Total Payroll		Expensed Payroll
Historical 2018 Test Year	86.0%	$	18,709,060	$	16,097,181
Average % Expensed 2015 thru 2018	85.7%				16,033,664
Additional Expensed for Normalized Year				$	(63,517)
Test Year Net Increase					2.6%
Net Additional Expensed for Normalized Year				$	(65,168)

Allocated to Operations & Maintenance Categories

Payroll Percentage Expensed History

		% Expensed	Total Payroll	Expensed Payroll
2	2015	86.1%	17,002,264	14,631,187
3	2016	85.9%	17,340,060	14,896,136
4	2017	84.8%	17,990,481	15,260,152
5	2018	86.0%	18,709,060	16,097,181
	Average over 4 years	85.7%		

Dakota Electric Association
TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL
STAFFING CHANGES

		Net Days Vacant	Incremental Wages Test Year	Wage Adjustment [1]
			($)	($)
Staffing Changes during Test Year	Category			
Member Service Representative - Bilingual (2 FTE's)	CA	125	18,628	9,314
Member Service Representative (2 FTE's)	CA	25	3,725	1,863
Energy Service Representative	CS	80	15,342	7,671
Lead Mechanic	AG	10	2,479	1,240
Mechanic (2 FTE's)	AG	129	30,456	15,228
Utility Services Secretary - PT	DM	50	7,157	3,579
Distribution System Operator Assistant	DO	64	10,179	5,090
Distribution System Operator	DO	56	12,305	6,153
Powerline Specialist Crew Chief	DM	41	11,785	5,893
Powerline Specialist Crew Chief	DM	19	5,461	2,731
Powerline Specialist Apprentice	DM	84	18,382	9,191
Powerline Specialist Apprentice	DM	274	59,959	29,980
Powerline Specialist Apprentice	DM	144	31,511	15,756
Powerline Specialist Apprentice	DM	34	7,440	3,720
Sr. Electrical Engineer	DO	87	26,934	13,467
Meter Technician	DO	127	31,468	15,734
System Design Manager	DO	29	10,964	5,482
Total		1,378	$ 304,175	$ 152,092
FTEs		4		50%
Distribution System Operator	DO	-252	(80,364)	(80,364)
Utility Services Superintendent	DM	-19	(8,900)	(8,900)
Vice President Engineering Services	AG	-28	(12,846)	(12,846)
Total Overlap				(102,110)
			Booked in Test Year	
Long Term Disability during Test Year				
Powerline Specialist Crew Chief	DM		10,049	94,866
New Positions Added during Test Year				
Director of Information Services Operations	AG		110,115	14,885
CIS/Billing Administrator	CA		3,635	60,665
Member Service Representative	CA		6,419	39,981
Total			130,218	210,397

Net Adjustment to Payroll for Staffing Changes	**$ 260,379**

[1] Additional wages which would have been booked had the individual been employed for the entire Historical Year assuming an average of 2 FTEs unfilled.

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL RELATED EXPENSE

	G/L Account Number	Rate: Historical Test Year	Rate: Future Test Year		Total Cost Historical Test Year
		(% of Payroll)	(% of Payroll)		($ Expensed)
Pension	81540-41	17.57%	16.71%	A	$ 2,680,484
Savings (401k)	81530-31	6.32%	6.77%	B	964,809
FICA Tax	81410	7.60%	7.60%		1,159,549
Life Insurance	81520	0.55%	0.60%		84,336
Workers' Compensation	82520	1.23%	1.32%		188,060
Medical Insurance	81510-15	12.55%	12.87%		1,915,268
State & Federal Unemployment	81420-30	0.16%	0.14%		23,855
Other-Retirement Health Benefits	81550	3.54%	0.93%	C	539,650
		49.5%	46.94%		$ 7,556,011
Pro Forma Test Year Expensed Payroll Benefits					$ 7,162,694
Adjustment					**$ (393,317)**
Historical Test Year Expensed Salaries & Hourly Wages			15,259,255		

Notes:

A - Per NRECA, effective January 2019, the salaried and hourly rate is 28.93% and has increased 29pp from 2018. The decrease as a percent of total payroll is due to employee turnover as new hires are not eligible for the Retirement & Pension Plan.

B- Beginning March 1, 2006, new hires are not eligible for the Retirement & Pension Plan, but are enrolled in a new 401k plan where DEA will contribute 5% of base pay and will match up to an additional 5% of base pay. DEA contributes only 4% to employees that are in the pension plan. When employees with the pension retire at the lower rate and are replaced by new hires at the higher rate, the average rate increases.

C-The decrease in the Other-Retirement Health Benefits is due to a 2018 yearend accrual adjustment to the post-employment FAS 106 benefit related to the increase in medical insurance. This increase is not anticipated in 2019.

Dakota Electric Association

TEST YEAR ADJUSTMENTS SUMMARY
ADJUSTMENTS TO PAYROLL AND BENEFITS

SUMMARY OF COMPENSATION CHARGED TO EXPENSE ACCOUNTS

Category	Historical Test Year Expensed Compensation	General Payroll Increase	Capital to Expense Changes	Staffing Changes	Adjusted Test Year Expensed Compensation
	($)	($)	($)	($)	($)
I Operations	2,985,569	77,906	(33,389)	(34,438)	**2,995,648**
I Maintenance	2,841,645	74,151	(31,779)	156,816	**3,040,833**
(Consumer Accounting	2,113,151	55,142	-	111,823	**2,280,116**
(Consumer Services	1,001,465	26,133	-	7,671	**1,035,269**
/ Administration & General	7,116,699	185,707	-	18,507	**7,320,913**
Other (Diversified projects)	38,652	1,009	-	-	**39,661**
Construction	-	-	-	-	-
Total	16,097,181	420,048	(65,168)	260,379	**16,712,440**

SUMMARY OF PAYROLL BENEFITS CHARGED TO EXPENSE ACCOUNTS

Category	Historical Test Year Expensed Benefits	Benefits on General Payroll Increase	Benefits on Capital to Expense Changes	Benefits on Staffing Changes	Base Benefits Adjustment	Adjusted Test Year Expensed Benefits
		46.94%	46.94%	46.94%	-2.58%	
	($)	($)	($)	($)	($)	($)
Operations	1,401,425	36,569	(15,673)	(16,165)	(72,949)	**1,333,207**
Maintenance	1,333,867	34,806	(14,917)	73,609	(69,432)	**1,357,933**
Consumer Accounting	991,912	25,884	-	52,490	(51,633)	**1,018,653**
Consumer Services	470,087	12,267	-	3,601	(24,470)	**461,485**
Administration & General	3,340,577	87,171	-	8,687	(173,889)	**3,262,546**
Other (Diversified projects)	18,143	474	-	-	(944)	**17,673**
Construction	-	-	-	-	-	-
Total	7,556,011	197,171	(30,590)	122,222	(393,317)	**7,451,497**

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER

<u>Adjustment to Depreciation</u>	
Depreciation on Existing Plant	
1. Depreciation expense for the month of December 2018:	$ 890,504
2. Multiply by 12 months.	12
3. Normalized Depreciation Expense on Existing Plant	$ 10,686,048
Depreciation for the Pro Forma Test Year	$ 10,686,048
Less Historical 2018 Depreciation	(10,281,975)
Adjustment for Test Year	$ 404,073
<u>Adjustment to Property Tax Expense</u>	
1. Property Tax booked in the Historical Test Year:	$ 3,371,493
2. Property Tax to be booked in the next 12 months:	3,550,000
Property Tax Adjustment	$ 178,507

Note:

Current annual depreciation rates are outlined in the 5-year depreciation study in Docket No. E111/D-17-505.

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER
(continued)

Projected Reduction in Total CIP Spending 2018 Actual to 2019 Budget			
2019 Budget CIP Spending		$	2,206,786
2018 Actual Spending			2,407,082
Adjustment for CIP Spending	908	$	(200,296)
Adjustment to Regulatory Filing Fees			
1. Indirect Assessments for 2019 Budget		$	344,000
2 Direct Assessments for 2019 Budget			85,000
Total Assessments		$	429,000
Assessments for the Pro Forma Test Year		$	429,000
Less Historical 2018 Filing Fees		$	(410,200)
Adjustment for Test Year		$	18,800

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER
(continued)

	FERC Acct		Project Code		
Adjustment for Rate Filing Expense					
Estimated Rate Filing Expense (excluding internal labor)			RATECASE19	$	410,000
Amortize over 5 years					5
Adjustment (to A&G Expense)	928			$	82,000
Adjustment for nonrecurring reimbursements					
Adjustment for nonrecurring reimbursements				$	-
Other Adjustments					
Normalize Contracted Services for Kubra Data Transfer Services				$	36,758
Normalize Contracted Services for Itineris					109,080
Normalize Collection Recovery Costs					27,358
Normalize Contracted Services for meter reading					13,952
Normalize for Circuits Redesign and advertising removal					2,300
Distributed Generation contracts terminated					19,320
Subsidiaries contracts terminated					6,129
Dispatching contracts terminated					24,308
Internet project completed (only depreciation remaining)					(8,496)
Removal of AGi project					(382,291)
New broadband lease agreement (shared expense with GRE)					33,077
Other Adjustments				$	(118,505)
Adjustment for Disallowed Expenses			Project		
Exclude Touchstone Energy Branding Project	920		BRANDING		(115,225)
Exclude Image bill insert	909		Portion of MKT		(7,667)
Customer Relations Disallowed Expenses:					
Exclude Customer Zoo Event	930		CUSEVENT		(37,608)
Subtract 50% of Donation Project $ Disallowed:					
Community Donations	426.1	50%	DONCOMM		(8,663)
Human Services Donations	426.1	50%	DONHUMSV		(6,873)
Special Donations	426.1	50%	DONSPEC		(9,500)
Youth Donations	426.1	50%	DONYOUTH		(13,958)
Other Donations	426.1	50%	Various		(250)
				$	(199,744)

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

I. Consumer and Sales Data for 2018 (As Recorded)

(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**Avg. No. Cons.**	**Energy Sales [1]**	**Billing Demand [1]**	**Revenue [1]**
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	99,322	867,819,897	N.A.	116,867,077
2	Residential & Farm Demand Control (32)	15	407,603	989	45,353
3	Electric Vehicle (33)	0	332,257	N.A.	25,854
4	Irrigation Service (36) Firm	9	301,498	3,464	90,636
5	Irrigation Service (36) Interruptible	382	8,585,963	81,869	961,923
6	Small General Service (41)	4,426	42,642,557	N.A.	5,744,594
7	Security Lighting Service (44) - Closed to New	831	446,106	N.A.	102,393
8	Street Lighting Service (44-2)	2,284	2,487,972	N.A.	463,839
9	Street Lighting System (44-1)	487	523,536	N.A.	70,135
10	Custom Residential Street Lighting (44-3)	12,233	7,432,586	N.A.	1,331,468
11	LED Security Lighting Service (44 -4)	338	63,709	N.A.	30,558
12	LED Street Lighting Member Owned(44-5)	11	8,056	N.A.	1,196
13	LED Street Lighting (44-6)	465	171,871	N.A.	51,719
14	Low Wattage Unmetered Service (45)	66	-	N.A.	7,888
15	General Service (46)	2,696	449,957,114	1,404,899	48,236,894
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	3	203,303	N.A.	19,781
18	Controlled Energy Storage (51)	1,280	10,853,238	N.A.	501,196
19	Controlled Interruptible Service (52)	6,403	49,078,197	N.A.	2,949,495
20	Residential & Farm Time of Day (53)	18	217,249	N.A.	27,157
21	General Service Time of Day (54)	6	1,143,456	7,338	134,668
22	Standby Service (60)	1	-	-	65,387
23	Full Interruptible Service (70)	233	384,258,036	870,612	24,613,715
24	Partial Interruptible Service (71)	27	25,529,544	102,790	2,062,689
25	Cycled Air Conditioning Service (80)	41,630	4,754,757	N.A.	(1,786,057)
26	Wellspring				6,959
27	**Total [2]**	107,135	1,852,463,748	2,471,961	202,630,477

[1] See Workpaper 12.

[2] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) 2019 Budget Avg No. Cons. [1]	(d) Energy Sales [2]	(e) Billing Demand [2]	(f) Revenue [3]
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	100,202	838,089,528	N.A.	114,332,035
2	Residential & Farm Demand Control (32)	15	378,000	917.2	42,670
3	Electric Vehicle (33)	88	300,960	N.A.	24,636
4	Irrigation Service (36) Firm	8	162,528	1,867.3	50,143
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	862,089
6	Small General Service (41)	4,431	42,537,600	N.A.	5,799,609
7	Security Lighting Service (44) - Closed to New	878	405,600	N.A.	102,369
8	Street Lighting Service (44-2)	2,269	2,405,280	N.A.	466,293
9	Street Lighting System (44-1)	470	521,040	N.A.	72,603
10	Custom Residential Street Lighting (44-3)	12,190	6,750,960	N.A.	1,334,683
11	LED Security Lighting Service (44 -4)	356	64,896	N.A.	31,109
12	LED Street Lighting Member Owned(44-5)	11	8,712	N.A.	1,297
13	LED Street Lighting (44-6)	597	202,152	N.A.	59,884
14	Low Wattage Unmetered Service (45)	71	-	N.A.	8,520
15	General Service (46)	2,750	462,000,000	1,442,500.4	50,261,766
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	*3*	172,800	N.A.	16,571
18	Controlled Energy Storage (51)	1,718	10,308,000	N.A.	459,736
19	Controlled Interruptible Service (52)	6,686	44,127,600	N.A.	2,634,418
20	Residential & Farm Time of Day (53)	18	216,216	N.A.	29,057
21	General Service Time of Day (54)	6	1,059,984	6,802.3	126,286
22	Standby Service (60)	1	-		66,840
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	23,144,467
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,151,089
25	Cycled Air Conditioning Service (80)	41,880	5,075,000	N.A.	(1,625,193)
26	Wellspring				23,370
27	**Total** [4]	108,165	1,824,313,200	2,496,964.3	200,480,307
28	Actual Revenue Recorded 2018				202,630,477
29	Adjustment				(2,150,170)

1 Pro Forma Test Year consumers are based on DEA's average number of 2019 budgeted consumers.
2 Energy Sales are based on average monthly sales using the higher of 7-10 year trend or budget multiplied by average budgeted 2019 number of customers. See Workpaper 13.
3 See page 13 through 21.
4 The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Residential & Farm Service (31)				($)
Fixed Charge	100,202	cons.	$9.00	10,821,816
Energy Charge	838,089,528	kWh		
Summer	257,025,312	kWh	$0.13080	33,618,911
Other	581,064,216	kWh	$0.11680	67,868,300
			Subtotal	112,309,027
RTA Charge [1]	838,089,528	kWh	$0.00250	2,095,224
Controlled Water Heater Credit	1,003	units	($6.00)	(72,216)
			Total	114,332,035
Residential & Farm Demand Control (32)				
Fixed Charge	15	cons.	$12.00	2,160
Demand Charge	917.2	kW		
Summer	182.2	kW	$14.70	2,678
Other	735.0	kW	$11.10	8,159
Energy Charge	378,000	kWh	$0.07600	28,728
			Subtotal	41,725
RTA Charge [1]	378,000	kWh	$0.00250	945
			Total	42,670
Electric Vehicle (33)				
Energy Charge				
Off Peak	280,402	kWh	$0.06740	18,899
On Peak	8,554	kWh	$0.41440	3,545
Other				
Summer	2,693	kWh	$0.13080	352
Other	9,311	kWh	$0.11680	1,088
			Subtotal	23,884
RTA Charge [1]	300,960	kWh	$0.00250	752
				24,636

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Irrigation Service (36)				
Firm Service				
Fixed Charge	8	cons.	$30.00	2,880
Demand Charge	1,867.3	kW		
Summer	902.3	kW	$26.35	23,776
Winter	2.5	kW	$20.95	52
Other	962.5	kW	$15.50	14,919
Energy Charge	162,528	kWh	$0.04990	8,110
			Subtotal	49,737
RTA Charge [1]	162,528	kWh	$0.00250	406
			Total	50,143
Interruptible Service				
Fixed Charge	384	cons.	$30.00	138,240
Demand Charge	74,388	kW	$4.55	338,463
Energy Charge	7,801,344	kWh	$0.04990	389,287
			Subtotal	865,990
RTA Charge [1]	7,801,344	kWh	($0.00050)	(3,901)
			Total	862,089
Small General Service (41)				
Fixed Charge	4,431	cons.	$14.00	744,408
Energy Charge	42,537,600	kWh		
Summer	10,541,910	kWh	$0.12690	1,337,768
Other	31,995,690	kWh	$0.11290	3,612,313
			Subtotal	5,694,489
RTA Charge [1]	42,537,600	kWh	$0.00250	106,344
Controlled Water Heater Credit	17	units	($6.00)	(1,224)
			Total	5,799,609

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Security Lighting Service (44)				
175 W MV	0	lights	N/A	0
100 W HPS	819	lights	$10.10	99,263
150 W HPS	4	lights	$11.99	576
250 W HPS	8	lights	$15.79	1,516
	831	lights	Subtotal	101,355
RTA Charge [1]	405,600	kWh	$0.00250	1,014
			Total	102,369
Street Lighting Service (44-2)				
175 W MV	-	lights	$15.23	0
250 W MV	3	lights	$18.16	654
400 W MV	-	lights	$23.25	0
100 W HPS	38	lights	$12.27	5,595
150 W HPS	646	lights	$14.16	109,768
250 W HPS	1,597	lights	$17.95	343,994
400 W HPS	1	lights	$22.38	269
	2,285	lights	Subtotal	460,280
RTA Charge [1]	2,405,280	kWh	$0.00250	6,013
			Total	466,293
Street Lighting System (44-1)				
175 W MV	-	lights	$10.52	0
250 W MV	-	lights	$13.46	0
400 W MV	-	lights	$18.54	0
100 W HPS	-	lights	$7.56	0
150 W HPS	101	lights	$9.46	11,466
200 W HPS	101	lights	$11.41	13,829
250 W HPS	272	lights	$13.25	43,248
400 W HPS	13	lights	$17.67	2,757
	487	lights	Subtotal	71,300
RTA Charge [1]	521,040	kWh	$0.00250	1,303
			Total	72,603

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Custom Residential Street Lighting (44-3)				
175 W MV	-	lights	$11.37	0
50 W HPS	81	lights	$6.70	6,512
100 W HPS	8,416	lights	$8.41	849,343
150 W HPS	3,732	lights	$10.30	461,275
250 W HPS	4	lights	$14.09	676
	12,233	lights	Subtotal	1,317,806
RTA Charge [1]	6,750,960	kWh	$0.00250	16,877
			Total	1,334,683
LED Security Lighting (44-4)				
LED, >4,500 Lumens	338	lights	$7.63	30,947
RTA Charge [1]	64,896	kWh	$0.00250	162
				31,109
LED Street Lighting Member Owned(44-5)				
A (40-80 watts)	-	lights	$ 4.81	-
B (81-150 watts)	-	lights	$ 6.71	-
C (151-250 watts)	11	lights	$ 9.66	1,275
D (251-350 watts)	-	lights	$ 13.05	-
E (351-450 watts)	-	lights	$ 16.52	-
	11		Subtotal	1,275
RTA Charge [1]	8,712	kWh	$0.00250	22
				1,297

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
LED Street Lighting (44-6)				
Standard				
>5,200 L, Coach (Post)	121	lights	$10.60	15,391
>5,200 L, Acorn (Post)	48	lights	$11.24	6,474
>7,000 L, Cobra (Mast)	91	lights	$8.31	9,075
>11,500 L, Shoebox	151	lights	$10.71	19,407
Basic				
>5,200 L, Coach (Post)	41	lights	$6.83	3,360
>5,200 L, Acorn (Post)	0	lights	$6.30	-
>7,000 L, Cobra (Mast)	53	lights	$6.51	4,140
>11,500 L, Shoebox	16	lights	$7.98	1,532
	521			59,379
RTA Charge [1]	202,152	kWh	$0.00250	505
				59,884
Low Wattage Unmetered Service (45)				
Fixed Charge	71	cons.	$10.00	8,520
General Service (46)				
Fixed Charge	2,750	cons.	$34.00	1,122,000
Demand Charge	1,442,500.4	kW		
Summer	413,627.7	kW	$12.26	5,071,076
Other	1,028,872.7	kW	$9.16	9,424,474
Energy Charge				
First 200 kWh/kW	264,418,387	kWh	$0.07760	20,518,867
Next 200 kWh/kW	158,964,776	kWh	$0.06760	10,746,019
Over 400 kWh/kW	38,616,837	kWh	$0.05760	2,224,330
			Subtotal	49,106,766
Discounts				
Primary Voltage			($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	462,000,000		$0.00250	1,155,000
			Total	50,261,766

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Municipal Civil Defense Sirens (47)				
Fixed Charge	66	cons.	$5.00	3,960
Geothermal Heat Pump (49)				
Energy Charge	172,800	kWh	$0.09400	16,243
			Subtotal	16,243
RTA Charge [1]	172,800	kWh	$0.00190	328
			Total	16,571
Controlled Off-Peak Space & Energy Storage (51)				
Energy Net Charge - Rate 31	*10,210,445*	kWh		
Summer	2,701,434	kWh	$0.04400	118,863
Other	7,509,011	kWh	$0.04400	330,396
Energy Charge - Rate 41	*46,106*	kWh		
Summer	6,874	kWh	$0.04400	302
Other	39,232	kWh	$0.04400	1,726
Energy Charge - Rate 46	*51,449*	kWh	$0.04400	2,264
			Subtotal	453,551
RTA Charge [1]	10,308,000	kWh	$0.00060	6,185
			Total	459,736
Interruptible Heating Service (52)				
Energy Net Charge - Rate 31	*43,026,625*			
Summer	10,488,495	kWh	$ 0.05500	576,867
Other	32,538,130	kWh	$0.05500	1,789,597
Energy Charge - Rate 41	*450,886*			
Summer	64,095	kWh	$0.05500	3,525
Other	386,791	kWh	$0.05500	21,274
Energy Charge - Rate 46	650,089	kWh	$0.05500	35,755
			Subtotal	2,427,018
RTA Charge [1]	44,127,600	kWh	$0.00470	207,400
			Total	2,634,418

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Residential & Farm Time of Day (53)				
Fixed Charge	18	cons.	$12.00	2,592
Energy Charge				
Peak Period				
Summer	49,267	kWh	$0.18800	9,262
Other	12,117	kWh	$0.17400	2,108
Off-Peak Period	154,832	kWh	$0.09400	14,554
		kWh	Subtotal	28,516
RTA Charge [1]	216,216	kWh	$0.00250	541
			Total	29,057
General Service Time of Day (54)				
Fixed Charge	6	cons.	$36.00	2,592
Demand Charge	6,802.3			
Peak Period				
Summer	960.1	kW	$24.85	23,858
Winter	436.9	kW	$18.95	8,279
Other	1,253.2	kW	$13.00	16,292
Maximum	4,152.1	kW	$4.75	19,722
Energy Charge	1,059,984	kWh	$0.04990	52,893
			Subtotal	123,636
Discounts				
Primary Voltage		kW	($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	1,059,984	kWh	$0.00250	2,650
			Total	126,286
Standby Service Large Power General (60)				
Generation Reservation Fee				
Summer	1,000	kW	$3.21	9,630
Winter	1,000	kW	$2.47	7,410
Other	1,000	kW	$1.74	10,440
Distribution Reservation Fee				
Primary	1,000	kW	$3.2800	39,360
Secondary		kW	$3.5100	0
			Total	66,840

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Full Interruptible Service (70)				
Fixed Charge	234	cons.	$110.00	308,880
Communication Fee	51		$8.70	5,324
Coinc. Demand Charge				
Summer	1,042.8	kW	$24.85	25,914
Winter	0.0	kW	$18.95	0
Other	0.0	kW	$13.00	0
Total Coinc Demand	1,042.8	kW		
Non-Coinc. Demand	858,880.1	kW	$4.75	4,079,680
Failure to Control	1,042.8		$5.00	5,214
Energy Charge	379,080,000	kWh	$0.04990	18,916,092
Discounts			Subtotal	23,341,104
Primary Voltage	47,311.12	kW	($0.15)	($7,097)
Primary Metering	-		(2.0%)	$0
RTA Charge [1]	379,080,000	kWh	($0.00050)	(189,540)
			Total	23,144,467
Partial Interruptible Service (71)				
Fixed Charge	28	cons.	$110.00	36,960
Communication Fee	17		$8.70	1,775
Coinc. Demand Charge				
Summer	3,212.2	kW	$24.85	79,823
Winter	2,980.2	kW	$18.95	56,475
Other	5,964.3	kW	$13.00	77,536
Total Coinc Demand	12,156.7	kW		
Non-Coinc. Demand	111,610	kW	$4.75	530,145
Excess Demand		kW	$5.00	0
Energy Charge	27,720,000	kWh	$0.04990	1,383,228
Discounts			Subtotal	2,165,942
Primary Voltage	6,622.67	kW	$0.15	(993)
Primary Metering	0		2.00%	-
RTA Charge [1]	27,720,000	kWh	($0.00050)	(13,860)
			Total	2,151,089

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Controlled Air Conditioning Service (80)				
Option 1		kWh	$0.00	0
Option 2				
Residential Rate 81/31	4,858,654	kWh	($0.03200)	(155,477)
Rate 81/41	216,346	kWh	($0.03200)	(6,923)
Rate 81/46	0	kWh	($0.03200)	0
	5,075,000	kWh		(162,400)
Option 3				
Residential Rate 82/31	35,158	cons.	($13.00)	(1,371,162)
Commercial	0	cons.	($13.00)	0
	35,158			(1,371,162)
Option 4				
Rate 84/41	4,699	tons	($6.50)	(91,631)
Rate 84/46	0	tons	($6.50)	0
	4,699			(91,631)
			Total	(1,625,193)
Wellspring				23,370
Grand Total	1,824,313,200	kWh	$	200,480,307

Estimate of Pro Forma
Test Year Purchased Power Expense

(a) Line No.	(b) Description		(c) Units			(d) Rate		(e) Cost
	Based on GRE Year 2019 Rates [1]							($)
1	**GRE General Purchases**							
2	Capacity Charge [2]							
3	Summer - Gross		1,169,412.0	kW				
4	Less Demand Credits		(188,852.0)	kW				
5	Summer - Net		980,560.0	kW	$	18.24	/kW	17,885,414
6								
7	Winter		841,113.0	kW				
8	Less Demand Credits		(151,142.0)	kW				
9	Winter - Net		689,971.0	kW	$	12.16	/kW	8,390,047
10								
11	Other		1,635,745.0	kW				
12	Less Demand Credits		(318,115.0)	kW				
13	Other - Net		1,317,630.0	kW	$	6.08	/kW	8,011,190
14	Total Demand - Net		2,988,161.0	kW				34,286,651
15								
16	Energy Charge							
17	Wholesale Solar		4,500,000	kWh	$	0.060494	/kWh	272,224
18	On Peak		620,577,032	kWh	$	0.059390	/kWh	36,856,070
19	Off Peak		1,248,141,635	kWh	$	0.046460	/kWh	57,988,660
20	Ancillary Charge		1,873,218,667	kWh	$	0.000090	/kWh	168,590
21								
22	Transmission Charge		3,119,782.8	kW	$	6.57	/kW	20,496,973
23	Ancillary Charge		3,119,782.8	kW	$	0.69	/kW	2,152,650
24								
25	ETS-Space Heating Off Peak		1,323,100	kWh	$	(0.023960)	/kWh	(31,701)
26	ETS-Interruptible Water Heating Off Peak		6,187,000	kWh	$	(0.026460)	/kWh	(163,708)
27	ETS-Electric Vehicle Off Peak		264,300	kWh	$	(0.026460)	/kWh	(6,993)
28	Peak Shave Water Heating (8 hr) Off Peak		14,844,800	kWh	$	(0.012460)	/kWh	(184,966)
29	Peak Shave Water Heating (8 hr) On Peak		6,362,100	kWh	$	(0.025390)	/kWh	(161,534)
30	Dual Fuel Off Peak		12,961,800	kWh	$	(0.009960)	/kWh	(129,100)
31	Dual Fuel On Peak		5,555,100	kWh	$	(0.022890)	/kWh	(127,156)
32	Air Conditioner Credit	(3 Mo.)				$5.00	/unit/mo.	(772,584)
33								
34	Standby Reservation Fee		1	cons.		$27,060.00	/year	27,060
35	Wellspring							23,370
36	MSR Credit							(45,040)
37	**Total Test Year Purchased Power Cost**							150,649,466
38	Actual Purchased Power Recorded 2018							149,330,034
39	Adjustment							1,319,432

1 Test Year Rates are GRE's Year 2019 updated rates. Includes a direct pass through of Wellspring costs.
2 The Test Year capacity is based on 2019 budget
3 Wholesale Solar purchases are 2019 budget.

<u>STATE OF MINNESOTA</u>

<u>BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION</u>

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates for
Electric Service in Minnesota

Docket No. E-111/GR-19-478

PREFILED DIRECT TESTIMONY OF
DOUGLAS R. LARSON
VICE PRESIDENT OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION,
for Authority to Increase Rates
for Electric Service in Minnesota

Docket No. E-111/GR-19-478

PREFILED DIRECT TESTIMONY OF
DOUGLAS R. LARSON
VICE PRESIDENT OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

I. QUALIFICATIONS

Q. Please state your name.

A. My name is Douglas R. Larson.

Q. Where are you employed?

A. I am employed by Dakota Electric Association (DEA, Dakota Electric, or Cooperative). Dakota Electric's headquarters are located at 4300 220th Street West, Farmington, Minnesota 55024.

Q. Please describe the business activities of Dakota Electric.

A. Dakota Electric Association was founded in 1937 as a non-profit, member-owned distribution electric utility. It serves about 108,000 members in an area covering much of Dakota County, just south of Minneapolis and St. Paul. Dakota Electric also provides electric service in portions of Scott, Rice and Goodhue counties.

Dakota Electric purchases wholesale electricity from Great River Energy (GRE), located in Maple Grove, Minnesota.

A twelve-person elected board of directors made up of members governs the Cooperative. Dakota Electric is also regulated by the Minnesota Public Utilities Commission and is the only rate-regulated electric cooperative in Minnesota.

Q. Please state your title and describe your responsibilities with Dakota Electric Association.

A. I am Vice President of Regulatory Services. In this position, I am responsible for 1) developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; 2) evaluating power supply issues through participation in meetings at Great River Energy; and 3) monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Q. What is your educational and professional background?

A. My educational and professional background is summarized in Schedule 1 attached to this direct testimony.

Q. Have you previously presented testimony before the MPUC?

A. Yes. Schedule 2 attached to this direct testimony identifies the electric and natural gas utility general rate case proceedings, electric service territory compensation hearings, the contested rulemaking and the certificate of need proceeding in which I have presented testimony before the MPUC.

Q. Have you submitted testimony to other state regulatory commissions?

A. Yes. Schedule 2 attached to this direct testimony also identifies the electric utility general rate case proceedings in which I have presented testimony before other state regulatory commissions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the analysis of Dakota Electric's revenue requirements, class cost of service study and proposed rates within the context of the 2018 Historical Test Year, adjusted for known and measurable changes.

Q. Please describe the organization of your direct testimony.

A. My direct testimony is organized around the following sections with topics covered as follows:

Section I — Qualifications
- Identification
- Educational and professional background
- Previous testimony

Section II — Purpose of Testimony
- Organization of testimony
- Identification of exhibits
- Identification of workpapers

Section III — Summary of Filing

Section IV — Revenue Requirements
- Statement of Operations
- Rate of Return

Section V — Cost of Service Study
- COS overview
- Identify COS content
- General procedure for conducting COS
- Identify and summarize COS results

Section VI — Other Cost Analyses
- Load Management Cost Analysis

- Monthly Fixed Charge Cost Analysis
- Coincidental Demand Charges
- Special Fees and Charges
- Line Extension Analysis
- Base Calculations for Resource and Tax Adjustment
- Air Conditioning Analysis
- Standby Rate Analysis
- Electric Vehicle Rate Analysis
- Residential TOU Analysis

Section VII Rate Design

- Approach to rate design
- Proposed rates

Section VIII Summary and Conclusion

Q. Please identify the exhibits included with your testimony.

A. The following exhibits are included as part of my testimony:

Exhibit__(DEA-1)	Statement of Operations - Present Rates
Exhibit__(DEA-2)	Determination of Revenue Requirements
Exhibit__(DEA-3)	Cost of Service Analysis
Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-5)	Statement of Operations - Proposed Rates
Exhibit__(DEA-6)	Comparison of Present and Proposed Rates
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-9)	Summary of Lead-Lag Study
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU Rate Analysis
Exhibit__(DEA-17)	Present Rate Schedules
Exhibit__(DEA-18)	Blackline Mark-up of Present Rate Schedules
Exhibit__(DEA-19)	Proposed Rate Schedules

Q. Please identify the documents included in the workpapers you have submitted:

A. The workpapers include the following documents:

1) Form 7s 2014-2018
2) Audited 2018 Financials and 2018 Annual Report
3) Accounting System Description and Cross-Reference Projects to Form 7
4) 2019 Budget (2017 & 2018 Actual)
5) Long Range Forecast
6) Lead-Lag Study Detail
7) Cost Allocation Policy
8) Depreciation Summary
9) Conservation Improvement Program
10) Estimate of System Losses and System Own Use
11) Individual Customer Actual 2018 Usage and Demand by Rate Class
12) Monthly Billed Sales 2013-2018
13) Sales History and Forecasted Test Year Normalization
14) Property Tax Detail
15) Travel, Entertainment and Related Employee Expenses
16) Test Year Adjustments Bridge Schedule
17) Long Term Interest Expense / Prudently Incurred
18) Advertising
19) Donations / Charitable Contributions
20) Organizational Dues
21) Minimum Size Method w/ Demand Adjustment
22) Guide to the Cost of Service Study
23) Street Lighting Analysis
24) Reconciliation
25) Smart Metering Statement

Q. Has the material included in your exhibits and workpapers been prepared by you or by others under your direction?

A. The exhibits and workpapers I am sponsoring have been prepared by myself and others at Dakota Electric. In addition, the cost of service study model was completed by Richard J. Macke at Power System Engineering, Inc.

III. SUMMARY OF FILING

Q. What are Dakota Electric's objectives in filing this general rate case?

A. Dakota Electric has two objectives in filing this general rate case. The first objective is financial. Dakota Electric's 2019 budget has negative operating margins of about ($2,250,000), making an increase in rates necessary. This general rate filing will allow the Cooperative to increase distribution operating revenues and achieve acceptable financial operating results. The second objective of this general rate filing is to make continuing adjustments to align class rates and revenue with the cost of providing service.

Q. Would you please summarize the revenue requirement, COS study results and proposed rate design results contained in your testimony?

A. Revenue Requirements -- Summary

The revenue requirements of the Cooperative simply refer to the total cost of doing business and are comprised of operating expenses plus margin requirements. By comparing the revenue requirements against present revenue, the adequacy of the present rates can be assessed; and a general change in rates can be discussed.

Operating expenses for the Cooperative (excluding interest) total $199,769,626. We have calculated a proposed Rate of Return (ROR) on rate base of 5.73 percent, resulting in a required revenue increase of $8,727,396 or 4.35 percent. The following table presents a summary of the revenue requirements analysis for the 2018 Test Year:

Table 1
Revenue Requirements Summary

		($)
1.	Operating Expenses (Excluding Interest)	199,769,626
2.	Margin Requirements	
	a. Rate Base	189,064,856
	b. Rate of Return	5.73%
	c. Return Required	10,831,846
	d. Less: Non-Operating Income	292,978
	e. Net Operating Income Required	10,538,868
3.	Total Revenue Requirements	210,308,494
4.	Revenue from Present Rates	
	a. Tariff Revenue (net of RTA)	200,480,307
	b. Other Operating Revenue	1,100,791
	c. Total Revenue	201,581,098
5.	Potential Increase (Decrease)	8,727,396
	or	4.35%

<u>Class Cost of Service -- Summary</u>

Once the overall revenue requirements analysis was complete, the class Cost of Service (COS) analysis was prepared by Power System Engineering, Inc. This analysis is aimed at identifying the cost responsibility of each rate class and uses the same model approved by the MPUC in our 2003, 2009, and 2014 general rate cases with refinements described later in my testimony. The COS is also useful in determining the cost components of each rate class (i.e. member, energy and demand costs). The results of the class COS analysis are summarized on the following table:

Table 2
Cost of Service Summary

Rate Class	Revenue Present Rates[1]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[2]
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	113,507,080	119,475,495	5,968,415	5.29
Small General Service (41)	5,732,872	6,242,283	509,411	8.94
Irrigation (36)	917,323	892,507	(24,816)	(2.72)
General Service (46,54)	50,669,263	50,536,453	(132,811)	(0.26)
C&I Interruptible (70,71)	25,436,728	27,455,236	2,018,508	7.98
Lighting	2,079,781	2,468,469	388,689	18.79
			Total System	4.35

It is important, at this point, to distinguish between the COS and actual rate design. Due to the limitations inherent to a COS analysis, these results should be viewed as providing a general range of where rates should be. It is, in fact, uncommon for rates to be designed <u>exactly</u> in line with COS results.

1 Includes an allocated share of Other Operating Revenue.
2 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

<u>Proposed Rates – Summary</u>

Using the completed COS analysis, and in conjunction with Dakota Electric management and board of directors, we developed proposed rates. These rates are designed to meet various objectives of Dakota Electric and are discussed later in my testimony. The following table summarizes the impact of the proposed rates on Dakota Electric's rate revenue by service schedule:

Table 3
Comparison of Revenue
Present and Proposed Rates

(a)	(b)	(c)	(d)	(e)	(f)
		Revenue	**Revenue**		
Line		**Present**	**Proposed**	**Increase (Decrease)**	
No.	**Rate Class**	**Rates**	**Rates**	**Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44)	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44-4)	31,109	31,434	325	1.04
12	LED Street Lghtg Member-Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49)	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	-	-

IV. REVENUE REQUIREMENTS

Q. Please summarize the concept of revenue requirements.

A. In order to ensure financial viability, the Cooperative's retail rates must generate sufficient revenue to meet operating expenses and margin requirements. The margin requirement must in turn be adequate to cover interest expense, meet our lenders financial covenants and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) the desired equity position. In this testimony I will refer to the total operating expense and margin requirement as the "revenue requirements" of the Cooperative. This is expressed by the following equation:

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENT

To evaluate a cooperative's revenue requirement and the adequacy of its present rate structure to meet the requirement, it is common practice to analyze revenue and costs for a 12-month period of time called the Test Year.

Q. What Test Year was used to determine revenue requirements?

A. The Test Year revenue requirements for the study were based on Dakota Electric's actual historical operations for calendar year 2018, with adjustments for known and measurable changes.

Q. Has a Statement of Operations been prepared for the Test Year based on the revenue generated by DEA's present rates?

A. Yes. Exhibit__(DEA-1) provides a Statement of Operations for the Test Year based on the revenue generated by DEA's present rates.

Page 1 of Exhibit__(DEA-1) provides a summary of the Statement of Operations for the historical Test Year calendar 2018. The results shown in Column C reflect an unadjusted Test Year as actually recorded on DEA's books for the period January 1, 2018 through December 31, 2018 and correspond to the results shown in Exhibit__(DEA-2), page 1, Column C. Column D summarizes the various normalizing adjustments to the revenue and expense accounts proposed by the Cooperative with the resulting adjusted Pro Forma Test Year shown in Column E.

Page 2 of Exhibit__(DEA-1) provides a summary of each of the proposed adjustments. Pages 3 through 10 of Exhibit__(DEA-1) provide the detailed calculations for the following adjustments:

- Payroll;
- Payroll benefits;
- Depreciation;
- Other Adjustments;
- Property taxes;
- Reduction in CIP spending 2018 actual to 2019 budget;
- Regulatory filing fees;
- Rate Case filing fees recovery over 5 years; and
- Net deduction for disallowed expenses.

Page 11 of Exhibit__(DEA-1) presents the average number of consumers, energy sales, billing demand and revenue for Dakota Electric's rate classes as recorded for calendar year 2018.

Pages 12 through 21 of Exhibit__(DEA-1) present the calculation of revenue under present rates for the Pro Forma Test Year. That is, these pages multiply Pro Forma Test Year number of consumers, energy sales and billing demand times appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Dakota Electric's present tariffed fixed, energy and demand rates for various rate schedules, including the Resource and Tax Adjustment (RTA) charges and/or credits that became effective on January 1, 2019. The calculation of forecasted Test Year billing units is shown in Workpaper 13. The forecasted billing units rely on regression analysis for the residential rate class which is most sensitive to fluctuating consumption based on changing weather. For those classes that do not experience such consumption fluctuations due to weather, the Test Year billing units reflect the higher of the 2019 budgeted units or a 10-year trendline analysis.

Finally, page 22 of Exhibit__(DEA-1) presents an overview of wholesale power costs.

Q. What are Dakota Electric's Test Year revenue requirements?

A. Exhibit__(DEA-2) summarizes the operating results for DEA on both an unadjusted and an adjusted basis for the Test Year ended December 31, 2018. A summary of the Operating Statement is provided as follows:

Table 4
Statement of Operations - Present Rates

Description	**2018 Actual**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	203,138,675	201,581,098
Operating Expenses[3]	197,774,614	199,769,626
Net Operating Income	5,364,061	1,811,472
Non-Operating Income		
Capital Credits	5,111,212	5,111,212
Other	292,978	292,978
Subtotal	5,404,190	5,404,190
Total Margins	10,768,251	7,215,662

[3] Before interest expense is deducted.

It should be emphasized that the Net Operating Income stated is before interest expense on long term debt is deducted.

Furthermore, it is important to distinguish between operating income or margins and total income. Use of the term "operating" is intended to designate revenue and expenses associated with the basic utility function (i.e., supplying electric distribution service to members). It is to be distinguished from Non-Operating Income, such as interest earnings from short-term investments and patronage capital credit assignments from associated organizations. Because Non-Operating Income is outside the operations and direct control of the distribution cooperative, it is not generally considered in establishing the revenue requirement for retail ratemaking purposes. Retail rates are generally designed to be sufficient, but only sufficient, to cover the operating revenue requirement.

Page 1, Column D of Exhibit__(DEA-2) shows that, in order to achieve the required ROR of 5.73 percent, present rates would need to be increased by $8,727,396 or about 4.35 percent.

Q. How was Dakota Electric's margin requirement calculated?

A. To complete the Test Year Revenue Requirement, an appropriate level of margin must be added to the previously determined operating expenses. In establishing the level of margin required to achieve the Cooperative's financial objectives, we have determined an appropriate return on rate base using a calculation methodology recommended by the Department of Commerce and approved by the Commission in our last two general rate cases.

Q. Please explain your determination of Rate of Return.

A. The Rate of Return method for establishing the Cooperative's margin requirement has been used by the Commission in Dakota Electric's general rate cases since we have been rate-regulated in the early 1980's. The ROR method is intended to ensure that earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners. When applied to cooperatives, the concept is intended to permit the development of sufficient margins to cover the cost of debt and equity capital. However, in the case of cooperatives, the term "return on equity" involves a totally different concept than it does for investor-owned utilities. Return on (or of) equity for cooperatives is related to the retirement, or rotation, of patronage capital. Thus, the ROR required for a cooperative must result in sufficient margins to:

1. Pay interest expense on long-term debt;
2. Rotate patronage capital as stated in the policy of the cooperative;
3. Maintain or achieve the desired equity position; while
4. Meeting the financial covenants of our lenders.

Q. Has the rate-based ROR approach as applied to cooperatives been endorsed by the MPUC?

A. Yes. The method was originally endorsed by the MPUC in 1976 in a case involving Anoka Electric Cooperative (Docket No. U-75-103). Since that time, it has been used in all other cases involving cooperatives, including DEA's last rate filing (Docket No. E-111/GR-14-482).

Q. Please provide an overview of Dakota Electric's Rate of Return calculation.

A. The calculations necessary to determine the Cooperative's overall Rate of Return (ROR) are shown on pages 2 through 8 of Exhibit__(DEA-2). Page 2 of Exhibit__(DEA-2) shows the calculation of the Cooperative's Rate Base, with page 3 providing the supporting detail for Materials & Supplies used in the determination of Rate Base. Page 4 summarizes Dakota Electric's loans with the National Rural Utilities Cooperative Finance Corporation (CFC), Farmer Mac, and CoBank. The Cooperative's overall cost of debt used in the Test Year is 3.77 percent. Page 5 of Exhibit__(DEA-2) reviews Dakota Electric's historic total capitalization (debt and equity) for the years 1998 through 2018. We note that the mean growth rate in historic total capitalization for 2013 through 2018 is estimated to be 3.52 percent. Page 6 of Exhibit__(DEA-2) shows the calculation of the natural logarithm asset growth rate. Dakota Electric applied the 5 year exponential growth rate in the rate of return calculation as was used in the last general rate case. The five year period encompasses near-term years with more certainty in the growth forecast and aligns with our general expectation of filing rate cases at approximately five year intervals. Page 7 of Exhibit__(DEA-2) presents various ratio calculations. Finally, page 8 of Exhibit__(DEA-2) shows the calculation of DEA's 5.73 percent proposed ROR on rate base.

Q. Please identify the input assumptions used to calculate the overall ROR on rate base.

A. The input assumptions used to calculate the overall ROR on rate base are as follows:

Asset Growth Rate	1.73%
Equity Ratio	53.085%
Debt Ratio	46.915%
Test Year Total Capital	$ 272,999,564
Test Year Total Equity	$ 173,151,167
Test Year Total Debt	$ 99,848,397
Annual Capital Credits	$ 3,500,000
Rate Base	$ 189,064,856
Cost of Long-Term Debt	3.77%

Q. Please identify the calculation for determining return on equity.

A. The calculation for determining the 4.14 percent return on equity is as follows:

$$\boxed{K = g + (CC/(ER \times TC))}$$

where: K = Rate of Return on Equity
g = Growth
CC = Capital Credits
ER = Equity Ratio
TC = Total Capital

Q. Please identify the calculation for determining overall cost of capital.

A. The calculation for determining the 3.97 percent overall cost of capital is as follows:

$$OCC = (ER \times K) + ((1 - ER) \times i)$$

where: OCC = Overall Cost of Capital
ER = Equity Ratio
K = Rate of Return on Equity
i = Cost of Long-Term Debt

Q. Please identify the calculation for determining overall rate of return on rate base.

A. The calculation for determining the 5.73 percent overall rate of return on rate base is as follows:

$$ROR = OCC \times (TC/RB)$$

where: ROR = Return on Rate Base
OCC = Overall Cost of Capital
TC = Total Capital
RB = Rate Base

Q. How does Rate of Return on Rate Base relate to the financial performance requirements of the Cooperative's lenders?

A. Rate of return on rate base is <u>not</u> a financial performance metric used by Dakota Electric's lenders.

Q. Please explain.

A. The financial performance metric used by our lenders is Modified Debt Service Coverage (MDSC). MDSC measures the number of times operating cash flow covers debt service on long-term debt. MDSC is calculated as follows:

> MDSC = (Operating Margins + Non-Operating Margins-Interest + Interest Expense + Depreciation and Amortization Expense for year + Cash received in respect of Generation and Transmission and other Capital Credits)/(All payments of principal and interest during calendar year)

For the National Rural Utilities Cooperative Finance Corporation (CFC), Dakota Electric must maintain at least a 1.35 modified debt service coverage ratio calculated as an average of the two highest, out of the most recent three years. The 1.35 MDSC is a <u>default threshold</u>.

For CoBank, Dakota Electric must maintain at least a 1.25 modified debt service coverage ratio each year. The 1.25 MDSC is an <u>annual default threshold</u>.

Q. How does the pro forma Test Year revenue requirement and proposed revenue increase translate to MDSC for the Cooperative?

A. The filed pro forma revenue requirement using the 5.73 percent calculated rate of return and proposed revenue increase results in a calculated MDSC of about 2.0.

Q. How do these results compare to the MDSC financial performance of other cooperatives?

A. Benchmark information from CFC for 1) all cooperatives in the country, 2) Minnesota cooperatives, and 3) cooperatives of similar size to Dakota Electric is as follows:

"US Total" MDSC:
Annual 5 yr. avg. = 1.84
2 of 3 yr. high avg. = 1.96
Minnesota MDSC:
Annual 5 yr. avg. = 1.69
2 of 3 yr. high avg. = 1.76
Similar Size Cooperative MDSC:
Annual 5 yr. avg. = 1.99
2 of 3 yr. high avg. = 2.19

Dakota Electric's calculated Test Year MDSC of about 2.0 is at the average of cooperatives of similar size to Dakota Electric.

Q. Please summarize Dakota Electric's revenue requirements in this proceeding.

A. A summary of the revenue requirements is presented in Table 5. The details of these calculations are provided in Exhibit__(DEA-2).

Table 5
Revenue Requirements Summary

		($)
1.	Operating Expenses (Excluding Interest)	199,769,626
2.	Margin Requirements	
	a. Rate Base	189,064,856
	b. Rate of Return	5.73%
	c. Return Required	10,831,846
	d. Less: Non-Operating Income	292,978
	e. Net Operating Income Required	10,538,868
3.	Total Revenue Requirements	210,308,494
4.	Revenue from Present Rates	
	a. Tariff Revenue (net of RTA)	200,480,307
	b. Other Operating Revenue	1,100,791
	c. Total Revenue	201,581,098
5.	Potential Increase (Decrease)	8,727,396
	or	4.35%

Q. What level of net operating income is DEA proposing?

A. DEA has established a proposed level of net operating income (before interest expense) of about $10,539,000. The calculation of this net operating income is shown above in Table 5 and in Exhibit__(DEA-2).

Q. What overall revenue increase is DEA requesting?

A. A summary of the proposed increase is shown in the above Table 5 with detailed calculations shown in Exhibit__(DEA-2). To eliminate the present revenue deficiency, annual revenue must be increased by $8,727,396 or approximately 4.35 percent.

V. COST OF SERVICE ANALYSIS

Q. Have you prepared a Cost of Service study for Dakota Electric?

A. Yes. A class COS analysis has been prepared to provide information to be used in designing rates. The basic objective of this analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach meaning that 1) costs are allocated on an average system-wide basis, and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data and this has been confirmed by the Commission's approval of our cost of service study and methods in past rate cases.

Q. Has Dakota Electric used the same cost of service study model approved by the Commission in your last general rate case?

A. Yes, the cost of service study model is the same model approved by the Commission in our last rate case, with one modification.

Q. Please explain the modification.

A. In the Commission's final Order in Dakota Electric's 2014 general rate case in Docket No. E-111/GR-14-482, Ordering Paragraph #8 required that:

> *Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.*

In compliance with this Order, we have incorporated a demand adjustment in the minimum size method used to classify specified distribution accounts within the class cost of service study. Workpaper 21 describes the calculation of minimum size classification factors for the respective distribution accounts, identifies the analysis used to determine the relevant demand adjustment, and incorporates the demand adjustment into the minimum size methodology. These demand adjusted classification factors are then applied in the COS. For a point of reference, we have also included COS summary results based on overall classification using the zero-intercept method.

Q. Please describe Exhibit__(DEA-3).

A. Exhibit__(DEA-3) includes the COS analysis for Dakota Electric. The detailed calculations and assumptions that go into the analysis are as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-7	Adjusted Statement of Operations
8-13	Classification of Revenue Requirements
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Analysis of Class Load Characteristics
25-40	Analysis of Class Demand Characteristics
41-42	Development of Allocation Factors

NOTE: To help facilitate review of the cost of service study, Dakota Electric has prepared a "Guide to the Cost of Service Study" that is submitted as Workpaper 22. This document provides a detailed review of methods used in the COS and incorporates answers to information requests submitted by the Department of Commerce in our last several rate cases.

Q. How should the results of a COS be used?

A. It is important to recognize some of the inherent limitations of such a study. First, it must be emphasized that there are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; and not as precise values.

Second, a COS analysis is directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to their assigned consumer classification.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as member acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is easily administered and understood by members.

With the above limitations in mind, a COS study can provide a useful guideline for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail members.

Q. Explain the general procedure for conducting a COS study.

A. The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

Step 1 - Classify the plant account records into basic cost causative categories.

Step 2 - Classify the Test Year expenses and margin requirement into the same cost causative categories.

Step 3 - Develop allocation factors for each rate class.

Step 4 - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

In this regard, it is important to note that Dakota Electric has used the same COS model that was approved in our last three rate cases, with a refinement to account for capacity (demand adjustment) provided by facilities identified in the minimum size method as ordered by the Commission in our last rate case.

Q. What do you mean by cost causative categories?

A. Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

1. Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.
2. Consumer - Costs that are the result of the number and location of each member and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense. In addition, a portion of distribution expenses are categorized using the results of the minimum size analysis.
3. Capacity - Costs which result from providing and maintaining operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual member service peak. Much of the expense of operating and maintaining a three phase backbone feeder would generally fall within this category as would the Demand Charge in the purchased power rate.
4. Energy - Costs which are related to the amount of energy used. The major item in this category is the Energy Charge in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	Consumer	Capacity	Energy
As Assigned		Power Supply Distribution Substation	Power Supply
	Primary Line Line Transformer Secondary & Service Meter Customer Accounting	Primary Line Line Transformer	

Q. Could you briefly explain the methodology used in assigning plant accounts to cost causative categories?

A. The cost causative classification of the various electric plant accounts is presented in pages 4 and 5 of Exhibit__(DEA-3). The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. <u>Intangible Plant (Acct. 301 to 303)</u> - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. <u>Land, Structures, Station and Battery (Accts. 360 to 363)</u> - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. <u>Primary Line and Devices (Accts. 364, 365, 366, 367)</u> - Assignment of the Primary Line and Device accounts was based on results of the "Minimum Size Method" to determine the consumer component share. A narrative and calculation of the minimum size method, with a demand adjustment, is provided in Workpaper 21. The remaining amount was then assigned to the capacity component.
4. <u>Line Transformers (Acct. 368)</u> - Classification of the Line Transformer account was approached in similar fashion using the "Minimum Size Method" with a demand adjustment. (See Workpaper 21.) Again, it was reasoned that there exists a certain

minimum transformer investment required to provide basic service to each consumer independent of energy usage or capacity requirements. This cost is assigned to the consumer component, while the remaining investment is considered capacity related.

5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.
6. Consumer Premise (Acct. 371) - The Consumer's Premises account is associated to lighting plant and was directly assigned to the Lighting Class.
7. Street Lighting (Acct. 373) - The street or security lighting account was assigned directly to the Lighting Class.
8. General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the general plant has minimal effect on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant was not warranted.

Q. Explain how revenue requirements were classified.

A. The Operating Statement for the Test Year forms the basis for the COS analysis. Actual expenses by account for the historical 12-month period were used to establish the pattern of the Test Year cost breakdown to the various accounts.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 8 through 13 of Exhibit__(DEA-3). The factors used in the expense classification are summarized in pages 14 through 17 of Exhibit__(DEA-3). The methodology and rationale for that methodology is discussed below:

1. Purchased Power (Acct. 555) - The Demand and Energy Charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively. This includes Transmission Charges which were assigned to the capacity component.
2. Distribution Operation and Maintenance (Accts. 580 - 598) - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 587, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
3. Consumer Accounting (Accts. 901 - 905) - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
4. Consumer Service and Information and Sales (Accts. 907 - 916) - Consumer Service and Information and Sales expenses are also considered consumer related expenses.
5. Administrative and General (Accts. 920 - 932) - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Thus, we have assigned 10 percent of these expenses to the

power supply function and the remainder in proportion to the total of all other expenses without power supply.

6. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the net plant account assignments.
7. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the net plant account assignments.
8. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
9. Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense and return on equity, both related to plant investment, it is reasonable to classify this cost in proportion to the net plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., rate base - ROR method).

Q. Discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented in pages 20 to 22 of Exhibit__(DEA-3). The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation

   Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.

2. Consumer Costs Allocations

   Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of Exhibit__(DEA-3) to recognize the higher cost of three phase service versus standard single phase service for each subcategory of consumer related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay at least a token portion of the consumer related expense, hence the 0.02 weighting factor.

3. Capacity Cost Allocations

Three different allocation factors were developed for the capacity component. (See pages 24 to 40 of Exhibit__(DEA-3) for the development of class demands):

a. Line transformer capacity related costs were allocated in accordance with the estimated undiversified non-coincidental annual peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

b. Distribution Substation and Primary Line capacity costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased Power Demand Charges were allocated in accordance with the average monthly coincidental class demands established by season.

d. Purchased Power Transmission Charges were allocated in accordance with the average monthly coincidental class demands

4. <u>Energy Cost Allocations</u>

Energy related costs were allocated on the basis of total energy sales in each rate class and further segmented into on-peak and off-peak energy.

Allocation factors for each category are developed in pages 41 to 42 of Exhibit__(DEA-3).

Q. Please summarize the results of the COS study performed for Dakota Electric.

A. Results obtained from the COS analysis are summarized in Tables 6, 7 and 8. Table 6 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 6
Cost of Service Summary

Rate Class	Revenue Present Rates[4]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[5]
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	113,507,080	119,475,495	5,968,415	5.29
Small General Service (41)	5,732,872	6,242,283	509,411	8.94
Irrigation (36)	917,323	892,507	(24,816)	(2.72)
General Service (46,54)	50,669,263	50,536,453	(132,811)	(0.26)
C&I Interruptible (70,71)	25,436,728	27,455,236	2,018,508	7.98
Lighting	2,079,781	2,468,469	388,689	18.79
			Total System	4.35

Table 7 shows a breakdown of the COS by cost category for each class.

Table 7
Cost Allocation Summary

Rate Class	Cost Category: Power Supply	Transmission	Distribution	Total
	($)	($)	($)	($)
Residential & Farm (31,32,53)	65,457,456	13,696,762	40,321,277	119,475,495
Small General Service (41)	3,298,400	706,106	2,237,776	6,242,283
Irrigation (36)	447,438	12,511	432,558	892,507
General Service (46,54)	36,036,904	7,229,676	7,269,873	50,536,453
Interruptible Service (70,71)	21,738,992	880,227	4,836,017	27,455,236
Street and Security Lighting	667,425	124,341	1,676,703	2,468,469
Total	127,646,615	22,649,623	56,774,205	207,070,443

4 Includes an allocated share of Other Operating Revenue.
5 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

Table 8 provides total costs by class expressed in terms of $ per customer per month (consumer component) and ¢ per kWh (capacity and energy components).

Table 8
Unit Cost Summary

Rate Class	Consumer Unit Cost	Demand Unit Cost	Energy Unit Cost
	($/cust.mo.)	(¢/kWh)	(¢/kWh)
Residential & Farm (31,32,53)	25.11	5.34	5.30
Small General Service (41)	32.65	5.29	5.30
Irrigation (36)	57.31	2.52	5.30
General Service (46,54)	60.71	5.18	5.30
Interruptible Service (70,71)	221.08	1.27	5.30
Street and Security Lighting	0.50	3.96	4.93

VI. OTHER COST ANALYSES

Q. Is any other cost analysis included in this filing besides the class COS study?

A. Yes, several other cost analyses are included in my exhibits as follows:

Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU Analysis –Schedule 56

Q. Please explain the load management cost analysis.

A. The load management cost analysis, shown in Exhibit__(DEA-4), presents the costs to provide service to Schedules 49, 51, and 52. These costs include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. In the case of storage service, the cost is calculated at 4.87¢ per kWh, while the cost for interruptible service is 6.31¢ per kWh. The cost for geothermal heat pump service is calculated at 11.07¢ per kWh. This cost analysis will form the basis for rate recommendations for Schedules 49, 51 and 52 described later in my testimony.

Q. Explain the exhibit that calculates monthly fixed charge costs.

A. Exhibit__(DEA-7) calculates the monthly costs that should be applied in the monthly fixed charge of retail rates. This exhibit first identifies the "customer" related costs allocated to each class in the cost of service study. While such costs have been allocated based on number of consumers, not all of these costs may be appropriate for recovery in the monthly fixed charge. As Dakota Electric testified in our last general rate cases, we believe it is appropriate for the monthly fixed charge to recover costs we incur to stand ready to provide electric service, excluding costs for primary line. Such costs to be included in the monthly fixed charge include the monthly cost of a transformer, meter and service, customer accounting, as well as taxes and margin associated with plant costs proposed for recovery in the monthly fixed charge. The monthly fixed costs identified for recovery in this analysis are as follows:

Residential	$15.01
Small General	$20.32
Irrigation	$41.19
General	$44.99
C&I Interruptible	$200.69

This cost analysis will form the basis for rate recommendations described later in my testimony.

Q. Discuss the calculation of Coincidental Demand Charges shown in Exhibit__(DEA-8).

A. The calculation of Coincidental Demand Charges reflects the wholesale demand-related charges Dakota Electric experiences from Great River Energy adjusted for distribution line loss. These calculations allow us to determine the summer, winter and other months' retail Coincident Demand Charges for the partial interruptible option and full interruptible option for Dakota Electric's Schedules 70 and 71.

Q. Explain the analysis for special fees and charges.

A. Exhibit__(DEA-10) presents an analysis of Dakota Electric's costs associated with special fees and charges. This exhibit calculates the labor, benefits, vehicles and other expenses associated with each special fee and charge. The results of this analysis will be used to update Dakota Electric's special fees and charges.

Q. Explain the line extension analysis.

A. Exhibit__(DEA-11) presents the costs of actual line extension project costs and charges. This exhibit also identifies the amount of plant investment Dakota Electric recovers through base rates for these line extensions. The plant investment amounts on a per kWh and per kW basis from this exhibit will be applied to commercial line extensions.

Looking at recovery for individual residential line extensions, Exhibit__(DEA-11) shows that Dakota Electric's base rates for residential members recover about $1,300 of distribution plant costs per residential member. By comparison, the average cost for extensions to individual residential members with no footage (includes material, labor, and vehicle costs to set a transformer and make the electrical connection) is about $3,600. To recover these basic extension costs, Dakota Electric proposes to increase the present flat fee for all individual residential extensions from $500 to $1,000. For new connections where the extension of cable is also required, Dakota Electric proposes to increase the present charge of $8.30 per foot to $11.00 per foot. These changes will also eliminate the application of a free footage allowance. This flat fee increase will provide additional revenue to cover more of the fixed costs associated with transformer and connection costs not otherwise recovered in base rates. We note that while these line extension costs are proposed to increase, the amount of increase is still below our extension costs not being recovered in base rates. Dakota Electric anticipates making continued incremental increases to individual residential line extension provisions in future rate case proceedings.

Q. Have you calculated new base factors for Dakota Electric's Resource & Tax Adjustment (RTA)?

A. Yes. Exhibit__(DEA-12) presents the calculation of RTA base components for cost of power, conservation and DSM expenditures, and property tax recovery. These new base components will be applied with the implementation of final rates.

Q. Please describe the calculation of power cost bases.

A. We have calculated several different power cost bases that track differences in wholesale power costs associated with specific retail rates. The calculation begins with an identification of an Energy Cost Adjustment (ECA) base. This ECA base relates to retail interruptible service that Dakota Electric provides to C & I members under interruptible service Schedules 70 and 71. This ECA base also applies to interruptible irrigation service provided under Schedule 36. (We note that firm irrigation service under Schedule 36 will be subject to the firm Power Cost Adjustment (PCA) base as described below.) The average wholesale energy cost per kWh applicable to the Energy Cost Adjustment base equals $0.0521 per kWh sold.

The next part of this exhibit calculates weighted power cost bases for Dakota Electric's load management rates including Schedules 51 and 52. For each rate schedule, we have calculated a weighted average wholesale power cost reflecting the relative purchase of water heating and space heating service under each schedule. Schedule 51 has a weighted power cost base per kWh sold of $0.0204. Schedule 52 has a weighted power cost base per kWh sold of $0.0352.

Next, we calculate the power cost base for rate Schedule 49, geothermal service. The base for this service includes the Cooperative's system average wholesale cost for energy, capacity, transmission, and ancillary service cost on a per kWh basis. The resulting Schedule 49 power cost base per kWh sold is $0.0813.

Finally, this exhibit calculates the Power Cost Adjustment (PCA) base applicable to Dakota Electric's remaining firm service rate schedules. This calculation begins with the Cooperative's total wholesale power cost, from which we subtract ECA power costs, Rate 51 power costs, Rate 52 power costs, Rate 49 power costs, and wholesale power cost pass-throughs for Wellspring, Member Specific Discount, Large Load High Load Factor Credit, Contract Rate Service, and Standby service. The result is a PCA base per kWh sold for Dakota Electric's firm service rate schedules of $0.0939.

Q. Explain the exhibit that evaluates cycled air conditioning.

A. Exhibit__(DEA-13) calculates the wholesale power cost savings achieved through cycling central air conditioners. Dakota Electric's cycled air conditioning program, in coordination with Great River Energy, provides for load control of central air conditioners typically during times of high demand. Air conditioners are controlled, or cycled, through fifteen minute on and fifteen minute off cycles during the respective control period. This exhibit calculates a diversified demand reduction for a typical controlled air conditioning unit. Based on this analysis, Dakota Electric recommends maintaining the present $13.00 per month <u>credit</u> in the months of June, July, and August, with a corresponding increase in the energy credit for those units that are separately metered and an increase in the per ton credit for commercial units.

Q. Please explain the Standby Analysis.

A. Exhibit__(DEA-14) calculates the primary and secondary distribution reservation fees for Standby Service. These costs are based on allocated costs to Dakota Electric's General

Service Schedule 46, which corresponds to the size and type of customers who would likely receive such standby service. In fact, the one standby member that Dakota Electric serves is of a size that would normally receive service under Schedule 46. This exhibit also updates the substation standby reservation fee consist with the methodology approved by the Commission when Dakota Electric proposed this fee in Docket No. E-999/CI-15-115.

Q. Please explain the Electric Vehicle Rate Analysis.

A. Exhibit__(DEA-15) updates the cost analysis that Dakota Electric submitted to the Commission when we proposed this service. The update reflects Test Year wholesale power supply and distribution costs. This rate has been very well received by members with electric vehicles, as we reported in a May 31, 2019, EV Informational Letter to the Commission. Based on participation and the high level of off-peak charging, Dakota Electric proposes to remove the "pilot" designation for this rate.

Q. Please explain the Residential TOU Analysis for Schedule 56.

A. Exhibit__(DEA-16) presents an analysis of costs and development of rate design for the residential time of use rate (Schedule 56) that was approved in our last rate case. Page 1 of this exhibit identifies wholesale power and distribution costs based on the cost of service study results for the residential class. Page 2 assigns these costs to respective cost components and time periods. Page 3 estimates billing units, on a total residential class basis, for the billing periods for this schedule. Finally, page 4 develops rates for each billing component using the cost assignments from page 2.

VII. RATE DESIGN

Various tables showing the results of the COS analysis are useful in discussing the design and evaluation of Dakota Electric's rates. These tables, which have been previously presented, are listed below:

Table	Description
Table 6	Cost of Service Summary
Table 7	Cost Allocation Summary
Table 8	Unit Cost Summary

Q. What objectives have you considered while developing proposed rate changes?

A. There are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.
6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the Cooperative must be made.

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as 1) the need to avoid abrupt changes and 2) the desire to achieve member-consumer acceptance also came into play. Thus, the dollar and percentage increase or decrease for each class as shown in Table 6 were tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Summarize the revenue impact of your proposed rates.

A. The rate design recommendations for the rate schedules contained and discussed herein result in an approximate $8,700,000 revenue increase. (We note that additional annual revenue will be provided by proposed changes to special fees and charges and from residential line extensions.) Table 9 presents a comparison of the Present and Proposed Rates by service schedule.

Table 9
Comparison of Revenue
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates ($)	(d) Revenue Proposed Rates ($)	(e) Increase (Decrease) Amount ($)	(f) Increase (Decrease) Percent (%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44)	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44-4)	31,109	31,434	325	1.04
12	LED Street Lghtg Member-Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49)	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	-	-

Q. Provide an overview of your approach to proposed changes in monthly fixed charges.

A. Exhibit__(DEA-7) identifies the cost basis for the proposed monthly fixed charges and was described above. Using these results and recognizing the historic difficulty of increasing this billing component, Dakota Electric proposes to increase the monthly fixed charge for residential service and small general service by $1 per month. This is the amount that was approved in prior rate cases after considerable testimony. For the other rate schedules, we propose aligning the monthly fixed charge on a similar cost basis percentage as the residential monthly fixed charge. The proposed monthly fixed charge changes 1) provide a more appropriate recovery of costs through this rate component, 2) reduce the amount of such costs that are otherwise recovered in volumetric charges, 3) align with similar charges the Commission has approved for neighboring utilities, and 4) make some progress toward cost recovery of this component in this rate case. We note, however, that this modest increase in the monthly fixed charge could result in taking 20 years or more to reach the appropriate cost recovery level for this component – based on the more recent approximate five-year cycle for Dakota Electric rate cases.

Q. Please describe the proposed rates.

A. A discussion of each of the proposed rates follows:

Residential & Farm Service (31)

The COS study shows the need to increase revenue from Residential & Farm (Schedules 31, 32 and 53) of about $5,968,000 or a 5.29 percent increase (see Table 6) over revenue from present rates. Dakota Electric is proposing a slightly lower increase for residential members. We propose to increase the monthly fixed charge from the present $9.00 to $10.00. The present summer Energy Charge of $0.1308 per kWh ($0.1333 per kWh including the RTA) is proposed to increase to $0.1379 per kWh for the summer months of June, July and August. The proposed Energy Charge for all other months will increase from $0.1168 per kWh ($0.1193 per kWh including the RTA) to $0.1239 per kWh. These proposed rates reflecting a “zeroing” of the present RTA and result in an increase to the Schedule 31 class of approximately 4.42 percent.

Table 10 Comparison of Present and Proposed Residential & Farm Service (31)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$9.00/month	$10.00 /month
Energy Charge		
Summer Months	$0.1308/kWh	$0.1379/kWh
Other Months	$0.1168/kWh	$0.1239/kWh
Average Charge		
RTA Charge	$0.0025/kWh	$0.0000/kWh

Dakota Electric is also proposing clarifying language to the Schedule 31 "Availability" clause and the addition of a clause describing billing for master-metered multi-tenant residential facilities. Both of these additions relate to the cost of service study and language we added to the to Schedule 31 related to service to apartments. The clarifying language proposed for the Availability clause indicates that Schedule 31 applies "to individually metered apartment units and mastered-metered multi-tenant complexes." This was the intent of the application that was adopted in our 2003 general rate case. It is reasonable for apartment units and apartment complexes to be billed under Schedule 31 since these are residential loads with residential load profiles. The new clause "Billing for Master-Metered Multi-Tenant Residential Facilities" specifies that "The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master-meter times the Fixed Charge plus the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment."

Residential & Farm Demand Control (32)

As previously noted, the COS study generally shows a required revenue increase from Residential members of about 5.29 percent. Accordingly, we recommend that the monthly Fixed Charge be increased from $12.00 to $13.00. We further propose to continue the seasonality in this rate structure through the Demand Charge by increasing the summer

Demand Charge from $14.70 per kW per month to $15.50 and the demand rate for all other months from $11.10 per kW to $11.90 per kW. We propose to increase the Energy Charge from the present tariff amount of $0.0760 per kWh ($0.0785 per kWh including the RTA) to $0.0810 per kWh. These proposed rates result in a revenue increase of about 4.36 percent for this rate schedule.

Table 11
Comparison of Present and Proposed
Residential & Farm Demand Control (32)

Description	Present Rate	Proposed Rate
Fixed Charge	$12.00/month	$13.00/month
Demand Charge		
Summer Months	$14.70/kW	$15.50 /kW
Other Months	$11.10/kW	$11.90/kW
Energy Charge	$0.0760/kWh	$0.0810/kWh
Average Charge		
RTA Charge	$0.0025	$0.0000

Electric Vehicle - Residential (33)

Dakota Electric received Commission approval to implement a pilot residential electric vehicle service in Docket No. E-111/M-12-874. This service (also referred to as Schedule EV-1) provides our residential members with an additional option for charging the batteries in their electric vehicle. Dakota Electric proposes to remove the "pilot" designation for this schedule and update the rates for this service based on the Test Year wholesale power and distribution cost analysis in Exhibit__(DEA-15). The comparison of present and proposed rates is shown in Table 12 below.

Table 12 Comparison of Present and Proposed Residential Electric Vehicle Service (33)		
Description	**Present Rate**	**Proposed Rate**
Energy Charges:		
Off-Peak	$0.0674/kWh	$0.0756/kWh
On-Peak	$0.4144/kWh	$0.4421/kWh
Other	Schedule 31	Schedule 31
RTA Charge	$0.0025/kWh	$0.0000/kWh

Irrigation Service (36)

The cost of service study shows the need to reduce revenues from irrigation service by about $25,000 or about 2.72%. However, to accommodate overall rate moderation among classes and to maintain relationships between similar billing components in other schedules, we propose a modest revenue increase for irrigation. The firm service irrigation rate structure presently includes a monthly fixed charge of $30 per month that is applied every month throughout the calendar year. We propose keeping this monthly fixed charge at $30 per month. The seasonal component for this firm service is incorporated in the Demand Charge with a present summer month Demand Charge of $26.35 which we propose to increase to $26.60. The $20.95 per kW per month Demand Charge in the winter months is proposed to increase to $21.20 per kW, and the $15.50 per kW Demand Charge in the spring and fall months is proposed to increase to $15.67 per kW. The present Energy Charge of $0.0499 per kWh ($0.0524 per kWh including the RTA) for all energy consumed throughout the year is proposed to change to $0.0521 per kWh.

Like the firm irrigation rate, the controlled irrigation rate will include a monthly fixed charge of $30.00 per month that will be applied during all months throughout the calendar year. Dakota Electric proposes no change in the present $4.55 per kW demand charge that recover distribution costs. (Since there is no seasonality in the wholesale power cost associated with controlled irrigation, the controlled irrigation rate does not incorporate any seasonality.) Finally, the proposed energy rate for controlled irrigation service will be the same $0.0521 per kWh proposed for firm irrigation service.

Table 13
Comparison of Present and Proposed
Firm Irrigation Service (36)

Firm Service		Present	Proposed
Fixed Charge	@	$30.00/month	$30.00 /month
Demand Charge			
Summer	@	$26.35/ kW/month	$26.60/kW/month
Winter	@	$20.95/ kW/month	$21.20 /kW/month
Other	@	$15.50/ kW/month	$15.67/kW/month
Energy Charge	@	$0.0499/kWh	$0.0521/kWh
RTA Charge	@	$0.0025/kWh	$0.0000/kWh

Table 14
Comparison of Present and Proposed
Interruptible Irrigation Service (36)

Interruptible Service		Present	Proposed
Fixed Charge	@	$30.00/month	$30.00 /month
Demand Charge	@	$4.55/ kW/month	$4.55/kW/month
Energy Charge	@	$0.0499/kWh	$0.0521/kWh
RTA Charge	@	($0.0005)/kWh	$0.0000/kWh

Small General Service (41)

The COS study shows the need to increase revenues from the Small General Service class in the amount of $509,000 or 8.94 percent. Dakota Electric proposes a more moderate overall revenue increase accomplished by increasing the monthly Fixed Charge for Small General Service from the present $14.00 per month to $15.00 per month. The present Energy Charge of $0.1269 per kWh ($0.1294 per kWh including the RTA) in the summer months of June, July and August is proposed to increase to $0.1375 per kWh and the present and the $0.1129 per kWh ($0.1154 per kWh including the RTA) Energy Charge during all other months is proposed to increase to $0.1235 per kWh. These proposed rates result in a revenue increase of about 6.86 percent for this rate schedule.

Table 15
Comparison of Present and Proposed
Small General Service (41)

Description	Present Rate	Proposed Rate
Fixed Charge	$14.00/month	$15.00/month
Energy Charge		
Summer Months	$0.1269/kWh	$0.1375/kWh
Other Months	$0.1129/kWh	$0.1235/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

General Service (46)

While the cost of service study shows a decrease of about 0.26 percent is justified for the General Service rate schedule, we are proposing a modest increase in revenue from this rate schedule to balance revenue from other classes.

The present General Service Schedule 46 includes a monthly Fixed Charge of $34.00, which we propose to keep at the same amount. The Demand Charge in the summer months of June, July and August is proposed to increase from $12.26 per kW to $13.70 per kW.

The Demand Charge during the remaining months is proposed to increase from $9.16 per kW to $10.60 per kW. These demand rate changes make progress in aligning demand charges with underlying capacity costs of providing service.

The proposed Energy Charges reflect load characteristics of customers on a monthly basis. This energy structure, commonly referred to as an “hours-use demand rate,” is based on the amount of energy that an individual member uses each month <u>in relation</u> to the member’s monthly non-coincident demand. That is, this energy rate is load-factor sensitive. The present energy rate for the first 200 kWh of energy consumption per kW of demand is $0.0776 per kWh ($0.0801 per kWh including the RTA) and is proposed to stay at $0.0776 per kWh. The next 200 kWh of energy consumption per kW of demand presently at $0.0676 per kWh ($0.0701 per kWh including the RTA) is proposed to stay at $0.0676 per kWh. All energy consumption above 400 kWh per kW of demand presently at $0.0576 per kWh ($0.0601 per kWh including the RTA) is proposed to stay at $0.0576 per kWh. Dakota Electric will continue to offer primary voltage discounts for members presently receiving primary service. The proposed General Service Schedule 46 rates result in an annual revenue increase of about 1.83 percent.

Table 16
Comparison of Present and Proposed
General Service (46) Rates

Description	Present Rate	Proposed Rate
Fixed Charge	$34.00/month	$34.00/month
Demand Charge		
Summer Months	$12.26 /kWh	$13.70 /kWh
Other Months	$9.16 /kWh	$10.60 /kWh
Energy Charge		
First 200 kWh/kW	$0.0776/kWh	$0.0776/kWh
Next 200 kWh/kW	$0.0676/kWh	$0.0676/kWh
Over 400 kWh/kW	$0.0576/kWh	$0.0576/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh
Discounts		
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%

Dakota Electric is also proposing two additions to billing provisions for Schedule 46. The first addition relates to the determination of billing demand. Prior to our 2003 general rate case, Dakota Electric had a provision in our general service rates that limited the billing impact for low load factor accounts. This provision was eliminated in the 2003 rate case and we find that it is reasonable and necessary to reintroduce a similar provision. Dakota Electric proposes to add language to the renamed "Determination of Demand" clause as follows: "In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month." Such a load factor billing limitation is reasonable since low load factor consumers generally exhibit lower system coincidence (distribution and wholesale power) than average consumers in the class.

The second addition relates to a proposed new clause describing billing for multi-use facilities. Multi-use facilities are properties that include a combination of commercial or institutional load along with some portion of residential domestic consumption. A growing example of this type of facility would be a property with independent living/apartment units where tenants may transfer to a unit with nursing or hospital type care. This could also include facilities with combined retail and residential living. The intent of this new clause is to provide clarification on billing for these facilities. Where electric service is provided through a single meter, the billing would be under either Schedules 41, 46 or 54. Where metering is separated between residential and commercial consumption, the service would be billed under Schedule 31 and Schedules 41/46/54 respectively.

Lighting Service (Rates 44, 44-1, 44-2, 44-3, 44-4, 44-5, 44-6)

The COS shows a need to increase lighting revenue by about 18.79 percent. This is a substantial increase. To ease this impact on members with lighting service, Dakota Electric proposes to implement this increase over the course of three years. (Dakota Electric took a similar approach in our 2003 rate case when implementing a higher increase for irrigation service.) Dakota Electric proposes the following three-year phase-in of lighting rates:

Table 17
Comparison of Present and Proposed
Rates for Lighting Service

Description	Present Rate per Month	Year 1 Rate per Month	Year 2 Rate per Month	Year 3 Rate per Month
Security Lighting Service (44)				
100 W HPS	$ 10.10	$ 10.74	$ 11.37	$ 12.01
150 W HPS	$ 11.99	$ 12.75	$ 13.50	$ 14.26
250 W HPS	$ 15.79	$ 16.80	$ 17.82	$ 18.83
Street Lighting Service (44-1)				
175 W MV	$ 10.52	$ 11.43	$ 12.34	$ 13.25
250 W MV	$ 13.46	$ 14.55	$ 15.65	$ 16.74
400 W MV	$ 18.54	$ 19.93	$ 21.32	$ 22.71
100 W HPS	$ 7.56	$ 8.24	$ 8.93	$ 9.61
150 W HPS	$ 9.46	$ 10.23	$ 11.01	$ 11.78
200 W HPS	$ 11.41	$ 12.33	$ 13.26	$ 14.18
250 W HPS	$ 13.25	$ 14.28	$ 15.32	$ 16.35
400 W HPS	$ 17.67	$ 18.86	$ 20.05	$ 21.24

Street Lighting Service (44-2)				
175 W MV	$ 15.23	$ 15.97	$ 16.70	$ 17.44
250 W MV	$ 18.16	$ 19.08	$ 20.01	$ 20.93
400 W MV	$ 23.25	$ 24.46	$ 25.68	$ 26.89
100 W HPS	$ 12.27	$ 12.78	$ 13.29	$ 13.80
150 W HPS	$ 14.16	$ 14.76	$ 15.37	$ 15.97
250 W HPS	$ 17.95	$ 18.81	$ 19.68	$ 20.54
400 W HPS	$ 22.38	$ 23.39	$ 24.41	$ 25.42
Custom residential Lighting (44-3)				
175 W MV	$ 11.37	$ 12.26	$ 13.14	$ 14.03
50 W HPS	$ 6.70	$ 7.28	$ 7.87	$ 8.45
100 W HPS	$ 8.41	$ 9.07	$ 9.73	$ 10.39
150 W HPS	$ 10.30	$ 11.08	$ 11.85	$ 12.63
250 W HPS	$ 14.09	$ 15.13	$ 16.17	$ 17.21
LED Security Lighting Service (44-4)				
LED (>4,500 lumens)	$ 7.63	$ 7.67	$ 7.71	$ 7.75
LED Street Lighting (44-5)				
A (40 – 80 watts)	$ 4.81	$ 5.04	$ 5.27	$ 5.50
B (81 – 150 watts)	$ 6.71	$ 7.06	$ 7.40	$ 7.75
C (151 – 250 watts)	$ 9.66	$ 10.16	$ 10.66	$ 11.16
D (251 – 350 watts)	$ 13.05	$ 13.71	$ 14.38	$ 15.04
E (351 – 450 watts)	$ 16.52	$ 17.37	$ 18.22	$ 19.07
LED Street Lighting "Standard" (44-6)				
Coach	$ 10.60	$ 10.17	$ 9.73	$ 9.30
Acorn	$ 11.24	$ 11.11	$ 10.98	$ 10.85
Cobra	$ 8.31	$ 8.41	$ 8.50	$ 8.60
Shoebox	$ 10.71	$ 10.71	$ 10.70	$ 10.70
LED Street Lighting "Basic" (44-6)				
Coach	$ 6.83	$ 6.67	$ 6.52	$ 6.36
Acorn	$ 6.30	$ 6.24	$ 6.18	$ 6.12
Cobra	$ 6.51	$ 6.67	$ 6.82	$ 6.98
Shoebox	$ 7.98	$ 8.21	$ 8.45	$ 8.68

Low Wattage Unmetered Service (45)

Dakota Electric proposes to increase the Low Wattage Unmetered Service Schedule 45 rate from $10.00 per month to $10.50 per month.

Table 18 Comparison of Present and Proposed Low Wattage Unmetered Service (45)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$10.00/month	$10.50/month

Municipal Civil Defense Sirens (47)

Dakota Electric is not proposing any changes in the monthly $5.00 fixed charge applicable to Municipal Civil Defense Sirens.

Table 19 Comparison of Present and Proposed Municipal Civil Defense Sirens (47)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$5.00/month	$5.00/month

Geothermal Heat Pump (49)

Dakota Electric's cost analysis for the Geothermal Heat Pump Rate is shown in Exhibit__(DEA-4). The costs for Schedule 49 include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. The cost for geothermal heat pump service is calculated at $0.1107 per kWh. We propose an increase in the energy charge for this service from the present tariffed rate of $0.0940 per kWh ($0.0959 per kWh including the RTA) to $0.103 per kWh. Since geothermal heat pump service is no longer offered as a special program rate through our wholesale power supplier, this service been closed to new members since our last rate case.

Controlled Energy Storage (51)

Dakota Electric's cost analysis for Controlled Energy Storage is shown in Exhibit__(DEA-4). The cost for Controlled Energy Storage service is calculated at $0.0487 per kWh. We propose an increase in the Energy Charge for this service from the present $0.0440 per kWh ($0.0446 per kWh including the RTA) to $0.0487 per kWh. This represents an increase of approximately 9.19 percent for this service.

Table 20 Comparison of Present and Proposed Controlled Energy Storage (51)		
Description	**Present Rate**	**Proposed Rate**
Net Energy Charge	$0.0440/kWh	$0.0487/kWh

Controlled Interruptible Service (52)

A cost analysis for Controlled Interruptible Service is shown in Exhibit__(DEA-4). The cost for Controlled Interruptible service is calculated at $0.0631 per kWh. Dakota Electric proposes an increase in the rate for this service from the present energy rate of $0.0550 per kWh ($0.0597 per kWh including the RTA) to a proposed energy rate of $0.0631 per kWh. This represents a 5.7 percent increase.

Table 21 Comparison of Present and Proposed Controlled Interruptible Service (52)		
Description	**Present Rate**	**Proposed Rate**
Net Energy Charge	$0.0550/kWh	$0.0631/kWh

Residential & Farm Time of Day (53)

The COS for Residential & Farm Time of Day service was incorporated in the COS study with the Residential & Farm Service Schedule 31. Since the COS for these classes is similar, we are proposing a similar revenue increase for Schedule 53. This revenue increase will be achieved by increasing the monthly Fixed Charge from the present $12.00 to $13.00. The present summer Peak Period Energy Charge of $0.1880 per kWh ($0.1905 per kWh including the RTA) will be increased to $0.21263 per kWh and the present other months Peak Period Energy Charge of $0.1740 per kWh ($0.1765 per kWh including the RTA) will be increased to $0.19863 per kWh. The Off-Peak Energy Charge will be changed from $0.0940 per kWh ($0.0965 per kWh including the RTA) to $0.09450 per kWh. These proposed changes result in an overall increase of about 4.36 percent.

Table 22
Comparison of Present and Proposed
Residential & Farm Time of Day (53)

Description	Present Rate	Proposed Rate
Fixed Charge	$12.00/month	$13.00/month
Energy Charges		
Peak Period:		
Summer	$0.1880/kWh	$0.21263/kWh
Other	$0.1740/kWh	$0.19863/kWh
Off-Peak	$0.0940/kWh	$0.09450/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

General Service Time of Day (54)

Dakota Electric proposes to realign component rates for Schedule 54 to track changes to other similar rate schedules. We propose to keep the monthly Fixed Charge for Rate 54 at the present $36.00. The Peak Period Demand Charge will be changed to $26.14 per kW in the summer months (June, July and August), $19.91 per kW in the winter months (December, January and February) and $13.67 per kW during all other months. The Maximum Demand Charge of $4.75 per kW will be increased to $5.25 per kW. The Energy Charge of $0.0499 per kWh ($0.0524 per kWh including the RTA) will be changed to $0.0521 per kWh. This proposed rate design results in a revenue increase of about 3.37 percent for this rate schedule.

Table 23 Comparison of Present and Proposed General Service Time of Day Service (54)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$36.00/month	$36.00/month
Demand Charges		
Peak Period:		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Maximum	$4.75/kW	$5.25 /kW
Energy Charge	$0.0499/kWh	$0.0521 /kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0025/kWh	$0.0000/kWh

Residential & Farm Time of Day (56)

(<u>NOTE</u>: *This service was originally identified as Schedule 55 when it was first proposed in our last general rate case. During that proceeding, we realized that the "55" code was already being used internally – so the final approved designation for this service is Schedule 56.*)

The cost analysis and development of the proposed rates for the Residential & Farm Time of Day service is detailed in Exhibit 16. Table 31 identifies the proposed charges for this service.

Table 24 Comparison of Present and Proposed Residential & Farm Time of Day (56)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$12.00/month	$13.00/month
Energy Charges		
Peak Periods:		
Summer	$0.2710/kWh	$0.2890/kWh
Winter	$0.2210/kWh	$0.2320/kWh
Other	$0.1750/kWh	$0.1880/kWh
Intermediate	$0.0970/kWh	$0.1060/kWh
Off-Peak	$0.0760/kWh	$0.0820/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

Standby Service (60)

The distribution reservation fees for standby service have been analyzed in the attached Exhibit__(DEA-14). This analysis reflects the average primary and secondary distribution costs on a per kW basis for our General Service Schedule 46 members. It also updates the substation standby reservation fee consist with the methodology approved by the Commission when Dakota Electric proposed this fee in Docket No. E-999/CI-15-115. Based on this analysis, we propose increasing the primary distribution reservation fee from $3.28 per kW to $3.89 per kW. The secondary distribution reservation fee is proposed to increase from $3.51 per kW to $4.02 per kW. The substation distribution reservation fee is proposed to decrease from $0.90 per kW to $0.81 per kW. The generation reservation fees for this service are a direct passthrough of such wholesale power standby reservation fees from Great River Energy and are updated annually as authorized in this schedule.

Interruptible Service - Full Interruptible Option (70)

The cost of service study shows a need to increase revenue from the C & I interruptible members by about 7.98 percent. We propose a more moderate revenue increase. We propose increasing the monthly Fixed Charge from $110.00 to $130.00 per month. Coincidental Demand Charges are proposed at $26.14 per kW in the summer months, $19.91 per kW in the winter months and $13.67 per kW during all other months. The Non-Coincidental Demand Charge will be increased from the present $4.75 per kW to $5.25 per kW. The Energy Charge will be increased from $0.0499 per kWh ($0.0494 per kWh including the RTA) to $0.0521 per kWh.

Table 25 Comparison of Present and Proposed Interruptible Service (Full Interruptible Option) (70)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$110.00/month	$130.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Non-Coinc. Demand Charge	$4.75/kW	$5.25 /kW
Energy Charge	$0.0499/kWh	$0.0521/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	($0.0005)/kWh	$0.0000/kWh

Interruptible Service - Partial Interruptible Option (71)

Dakota Electric proposes the same retail rates for Schedule 71 as Schedule 70. The difference between these two services is that Schedule 70 consumers agree to fully interrupt their load during specified load control periods. Schedule 71 members, however, agree to reduce their load during control periods but not necessarily to zero. Accordingly, these consumers will have some portion of their load on during the control periods.

Table 26 Comparison of Present and Proposed Interruptible Service (Partial Interruptible Option) (71)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$110.00/month	$130.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Non-Coinc. Demand Charge	$4.75/kW	$5.25 /kW
Excess Demand	$5.00/kW	$5.00/kW
Energy Charge	$0.0499/kWh	$0.0521/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0060/kWh	$0.0000/kWh

Cycled Air Conditioning Service (80)

Dakota Electric's pricing for the four options under cycled air conditioning service reflect the savings we experience in wholesale capacity charges by members agreeing to control their air conditioners during peak periods. An analysis of wholesale power cost savings associated with cycled air conditioning is presented in Exhibit__(DEA-13). Based on this analysis, we propose no changes in the credit provided to the members participating in cycled air conditioning. The proposed rates for these options are presented below:

Table 27
Comparison of Present and Proposed
Controlled Air Conditioning Service (80)

Description	Present Rate	Proposed Rate
Option 1		
Option 2	($0.0320)/kWh	($0.0320)/kWh
Option 3	($13.00)/month	($13.00)/month
Option 4	($6.50)/ton/month	($6.50)/ton/month

Q. Have you prepared comparisons of the Present and Proposed Rates?

A. Yes, I have. Exhibit__ (DEA-6) provides several different comparisons of the present versus proposed rates as follows:

- Comparison of Present and Proposed Rates
- Comparison of Revenue under Present and Proposed Rates
- Comparison of Bills under Present and Proposed Rates for Selected Classes

Q. Is Dakota Electric proposing changes to other charges in addition to the rate schedules identified above?

A. Yes. Dakota Electric is proposing changes to its special fees and charges per occurrence as follows:

Description	Current Charge	Proposed Charge
Meter Test at Customer's Request		
Single phase	$85.00	$95.00
Three phase	$100.00	$110.00
Bad Check	$15.00	$11.50
Reconnection Charge (after disconnect, same customer)		
Self-Contained Meter:		
Normal working hours	$50.00	$55.00
After hours	$130.00	$145.00
Transformer-Rated Meter:		
Normal working hours	$175.00	$185.00
After hours	$315.00	$340.00
Service Charge (outside normal working hours when problem is not with DEA equipment)	$280.00	$340.00
Load Management Service Charge:		
Normal working hours	$70.00	$80.00
After hours	$140.00	$160.00
Pulse Meter	$500.00	$750.00
~~Temporary Service:~~		
~~Non-winter months~~	~~$205.00~~	NA
~~Winter months~~	~~$340.00~~	NA
Transfer/Connection	$ 17.50	$17.50

These changes are supported by the cost analysis presented in Exhibit__(DEA-10). The Temporary Service special fees listed are being deleted since there is already language in our Rate Book (Section VI, Sheet 8) that describes the provision of Temporary Service. This sheet states that "When installing temporary service to a member, Dakota Electric Association will require that the member bear the cost of the installation and removal of service in excess of any salvage realized." While this language has been in place, Dakota Electric has been charging according to the rates identified for Special Fees or Charges. It is more appropriate for these installations to pay the actual costs for each specific installation.

Q. Are there any other proposed changes?

A. As I mentioned earlier, Dakota Electric is also proposing to update its line extension charges. The present line extension policy provides a base footage allowance of 75 feet, with a $500.00 charge imposed on all individual residential line extensions plus $8.30 per foot for extensions in excess of 75 feet. Based on the analysis in Exhibit__(DEA-11), Dakota Electric proposes to change individual residential line extension charges to a base fee of $1,000.00 plus $11.00 per foot for each foot of the extension (no free footage allowance). We are also proposing language that would refund the amount paid for individual residential line extensions that exceed actual costs for the extension. This proposal for individual residential line extension charges 1) better reflects costs recovered through base rates, 2) helps ensure that new members are paying a more reasonable share of line extension costs, 3) limits payments to no more than actual costs, while 4) reducing the cost burden on existing ratepayers.

Dakota Electric also proposes to update the line extension factors applicable for extensions to members receiving service under Schedule 41, Schedule 46, and Schedules 70/71. These factors are based on the analysis shown in Exhibit__(DEA-11). We also propose to add a factor and line in the calculation description for extensions to multi-tenant residential complexes. This proposed credit per residential unit for multi-tenant master-metered residential buildings is consistent with the residential credit used in the analysis for individual residential line extensions.

Q. Have you prepared revised tariff pages reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit__(DEA-17) includes Dakota Electric's present rate schedules. This exhibit is followed by Exhibit__(DEA-18) that includes marked-up versions of present rate schedules showing all proposed additions and deletions. (The software used for this purpose specifically identifies text that has been deleted. Text proposed for addition is shown as underlined.) Finally, Exhibit__(DEA-19) presents a "clean" version of proposed rate schedules.

VIII. SUMMARY & CONCLUSION

Q. Please summarize your testimony and requests for Commission action.

A. Dakota Electric requests that the Commission:

1. Authorize an overall revenue increase of $8,727,396 or about 4.35 percent.
2. Approve the pro forma Test Year Revenue Requirements contained in Exhibit__(DEA-1).
3. Approve a Rate of Return on Rate Base of 5.73 percent as calculated in Exhibit__(DEA-2).
4. Approve the Cooperative's Cost of Service study as contained in Exhibit__(DEA-3), including the use of the minimum size method (with demand adjustment) in this and future general rate proceedings for the Cooperative.
5. Approve the charges for retail rate schedules as described in this testimony and contained in Exhibit__(DEA-6) and proposed tariff pages included in Exhibit__(DEA-18) and Exhibit__(DEA-19).
6. Approve the RTA base components contained in Exhibit__(DEA-12) and as reflected in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).
7. Approve the proposed Special Fees and Charges shown in Exhibit__(DEA-10) and as reflected in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).
8. Approve the proposed changes for individual residential line extensions as described in this testimony and analyzed in Exhibit__(DEA-11).
9. Approve the proposed modifications/clarifications to tariff pages in Section VI of the Cooperative's rate book as reflected in in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).

Q. Does this conclude your prefiled Direct Testimony?

A. Yes, it does.

Schedule 1
Professional and Educational Background
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-19-478

PROFESSIONAL EXPERIENCE

Dakota Electric Association – Farmington, Minnesota (2008 – Present)

Vice President of Regulatory Services

Responsible for regulatory matters including developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; evaluating power supply issues through participation in meetings at Great River Energy; and monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Power System Engineering – Blaine, Minnesota (1998 – 2008)

Vice President of Rates and Financial Planning

Senior Rate and Financial Analyst

Manager of PSE's Blaine, Minnesota office. Responsibilities include preparation of rate and cost of service analyses for electric cooperative and municipal clients; economic evaluation of mergers, acquisitions and special programs; key account analysis; development of large power contracts and special rates; development of restructuring plans and various elements of such plans; and development of financial forecast and economic feasibility studies.

Dakota Electric Association – Farmington, Minnesota (1992 – 1998)

Director of Regulatory & Legislative Affairs

Coordinated and/or prepared all necessary information pertaining to rate filings, cost of service studies, new rate proposals and miscellaneous tariff filings. Monitored state and federal electric utility and environmental legislation to determine the potential effect on Dakota Electric's operations as a distribution cooperative. Participated in statewide rulemaking proceedings initiated by state agencies that affect electric utility operations. Prepared and conducted conservation, rate and industry-related presentations for consumer and other public meetings.

Dakota Energy Alternatives, Inc. – Farmington, Minnesota (1993 – 1998)

President/CEO – Unregulated Business Activities

Vice President of Business Operations

Supervised staff of professional engineers and support staff who sold and installed standby generation for commercial and industrial customers. Established relationships/partnerships with organizations to expand the standby generation business. Worked with officers to evaluate new business ventures.

Minnesota Department of Public Service – St. Paul, Minnesota (1986 – 1992)

Rate Analyst

Filed testimony in utility rate cases regarding conservation, marketing, cost of service and rate design. Reviewed service area disputes between utilities and complaints from customers and recommended corrective actions. Presented testimony to establish compensation for municipal service territory acquisitions. Reviewed miscellaneous utility filings and prepared recommendations for Public Utilities Commission action. Also participated in Public Utilities Commission task forces to revise Minnesota Rules.

Minnesota Department of Energy & Economic Development, Energy Division
St. Paul, Minnesota (1983 – 1986)

Research Analyst

Responsible for filing testimony in utility rate cases regarding conservation planning and the calculation of cost-effective utility programs. Reviewed utility conservation programs and prepared comments for the Public Utilities Commission.

EDUCATION

University of Minnesota – Minneapolis, Minnesota
Master of Business Administration
St. Olaf College – Northfield, Minnesota
Bachelor of Arts Degree in Economics

Schedule 2
Regulatory Proceedings
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-19-478

Minnesota

Docket Number	Utility	Type of Proceeding
G-009/GR-84-128	Montana-Dakota Utilities	Rate Case
G-007/GR-84-669	Inter-City Gas	Rate Case
G-002/GR-85-108	Northern States Power	Rate Case
G,E-999/R-86-322	Cold Weather Rules	Rulemaking
E-001/GR-86-384	Interstate Power	Rate Case
E-221,148/SA-87-661	City of Buffalo & Wright-Hennepin Cooperative	Service Territory
E-002/GR-87-670	Northern States Power	Rate Case
E-132, 299/SA-88-270	City of Rochester & Peoples Cooperative	Service Territory
E-132,299/SA-88-996	City of Rochester & Peoples Cooperative	Service Territory
E-002/GR-89-865	Northern States Power	Rate Case
E-309,124/SA-89-778	City of Shakopee & Minnesota Valley Coop	Service Territory
G-010/GR-90-678	Midwest Gas	Rate Case
E-002/GR-91-001	Northern States Power	Rate Case
E-002/CN-91-019	Northern States Power	Certificate of Need
E-111/GR-91-074	Dakota Electric Association	Rate Case
E-111/GR-03-261	Dakota Electric Association	Rate Case
E-111/GR-09-175	Dakota Electric Association	Rate Case
E-111/GR-14-482	Dakota Electric Association	Rate Case

Kansas

Docket Number	Utility	Type of Proceeding
01 PNRE 058-RTS	Pioneer Electric Cooperative	Rate Case

Iowa

Docket Number	Utility	Type of Proceeding
RPU-02-1	Linn County REC	Rate Case

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to File, Establish, and make Effective
Revised Rates for the Sale of Electricity

Docket No. E-111/GR-19-478

Volume 1: Transmittal Documents
Interim Petition
Testimony and Exhibits

September 19, 2019

Daniel P. Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

SUBJECT: In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota
Docket No. E-111/GR-19-478

Dear Mr. Wolf:

Dakota Electric Association respectfully submits this Application for Authority to Increase Electric Rates (Application) pursuant to Minnesota Statutes 216B.16, Subd. 1. The Application includes changes in present rates and modifications to Dakota Electric Association's special fees and charges.

The name, address, and telephone number of the Cooperative and attorney are as follows:

Representing Attorney:
Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402-4629
(612) 604-6511

Utility Filing for Rate Change:
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
(651) 463-6327

Since our last general rate case was filed in 2014, Dakota Electric has experienced steadily increasing costs in providing electric distribution service. Dakota Electric's 2019 budget anticipates a net operating margin of about $2,250,000 making an increase in rates necessary and unavoidable. Based on our Historical 2018 Test Year operating results (adjusted for known and measurable changes), this filing documents the need for an annual revenue increase of about $8,700,000 or about 4.3 percent.

If the Commission elects to suspend the proposed rate increase under Minnesota Statute 216B.16, Subd. 2, we request that, pursuant to Minnesota Statute 216B.16, Subd. 3, an interim rate increase of approximately $6,000,000 or about 3.0 percent be effective beginning with consumption occurring on and after November 18, 2019, subject to refund (Agreement to Refund attached) should the Commission ultimately approve a lower final revenue level.

We request implementation of the proposed rates within 10 months of the date of Application and request that a Commission Order is received at the beginning of August 2020. However, we understand that multiple general rate proceedings will be filed with the Commission this year. Accordingly, Dakota Electric is willing to provide a limited waiver of the 10-month statutory timeframe, extending the disposition of this case, if such an extension is necessary.

Dakota Electric's Application consists of the following:

Volume 1	Transmittal Documents
	Interim Rate Petition
	Testimony and Exhibits (including proposed rates)
Volume 2	Workpapers (supporting documentation)

To facilitate the review and confirmation of required filing information, attached is a document that identifies Dakota Electric's general rate case compliance requirements with an indication of where each compliance document is located in our submission. These compliance requirements include provisions in Minnesota Rules, Minnesota Statutes, Commission Policy Statements, and the final orders from our last two general rate cases (Docket No. E-111/GR-09-175 and Docket No. E-111/GR-14-482).

Enclosed is a copy of the official notice we propose to provide to customers as a bill insert and to counties and municipalities in our service area through a separate mailing. Upon approval we will begin sending this notice to customers.

In addition to our electronic filing, notice of this general rate case has been sent to those on the Cooperative's general service list and a list of potentially interested persons provided by Commission staff.

Sincerely,

Greg Miller

Gregory C. Miller
President and Chief Executive Officer

Dakota Electric Association
General Service List

Daniel P. Wolf, Exec. Sec.
MN Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Sharon Ferguson
MN Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2198

Eric Swanson
Winthrop & Weinstine
225 South 6th Street, Suite 3500
Minneapolis, MN 55402-4629

Ron L. Spangler, Jr.
Rate Case Manager, Regulatory Services
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538

David R. Moeller
Attorney
Minnesota Power
30 West Superior St.
Duluth, MN 55802

John Lindell
Attorney General's Office - RUD
1400 Bremer Tower
445 Minnesota Street.
St. Paul, MN 55101

Pam Marshall
Energy Cents Coalition
823 East 7th Street
St. Paul, MN 55106

Corey Hintz
Dakota Electric Association
4300-220th Street West
Farmington, MN 55024

Doug Larson
Dakota Electric Association
4300-220th Street West
Farmington, MN 55024

Dakota Electric Association
List of Potentially Interested Persons
General Rate Case
Docket No. E-111/GR-19-478

Jody Johnson
Executive Assistant
Prairie Island Indian Community
jody.johnson@piic.org

Shannon Geshick
Grants and Legislative Director
Minnesota Indian Affairs Council (MIAC)
shannon.geshick@state.mn.us

Heather Westra
Prairie Island Indian Community
heather.westra@piic.org

Certificate of Service

I, Cherry Jordan, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket No. E-111/GR-19-478

Dated this 19th day of September 2019

/s/ Cherry Jordan

____
Cherry Jordan

September 19, 2019

"AGREEMENT TO REFUND"

I, Gregory C. Miller, President and Chief Executive Officer, acting on behalf of Dakota Electric Association, do hereby agree that the Association will refund any portion of the increase in interim rates, determined by the Minnesota Public Utilities Commission to be unreasonable, together with interest thereon.

Greg Miller

____

Gregory C. Miller, President and
Chief Executive Officer
DAKOTA ELECTRIC ASSOCIATION
Farmington, Minnesota 55024

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matt Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates
for Electric Service in Minnesota

Docket No. E-111/GR-19-478
September 19, 2019

SUMMARY OF RATE INCREASE PETITION

On September 19, 2019, Dakota Electric Association submitted an Application for Authority to Increase Electric Rates (Application) pursuant to Minnesota Statutes 216B.16, Subd. 1. The Application includes changes in present rates and modifications to Dakota Electric Association's special fees and charges.

Since our last general rate case was filed in 2014, Dakota Electric has experienced steadily increasing costs in providing electric distribution service. Dakota Electric's 2019 budget anticipates a negative net operating margin of about $2,250,000, making an increase in rates necessary and unavoidable. Based on our Historical 2018 Test Year operating results (adjusted for known and measurable changes), this filing documents the need for an annual revenue increase of about $8,700,000 or about 4.3 percent.

If the Commission elects to suspend the proposed rate increase under Minnesota Statute 216B.16, Subd. 2, we request that, pursuant to Minnesota Statute 216B.16, Subd. 3, an interim rate increase of approximately $6,000,000 or about 3.0 percent be effective beginning with consumption occurring on and after November 18, 2019, subject to refund (Agreement to Refund attached) should the Commission ultimately approve a lower final revenue level.

We request implementation of the proposed rates within 10 months of the date of Application and request that a Commission Order is received at the beginning of August 2020. However, we understand that multiple general rate proceedings will be filed with the Commission this year. Accordingly, Dakota Electric is willing to provide a limited waiver of the 10-month statutory timeframe, extending the disposition of this case, if such an extension is necessary.

Dakota Electric Association
General Rate Case Compliance Requirements
Docket No. E-111/GR-19-478

MN Rule	Description	Compliance
Minn. R. 7825.3200(A)	General rate changes shall include items prescribed in Minn. R. 7825.3300 to 7825.4400	See Minn. R. 7825.3300 to 7825.4400 below
Minn. R. 7825.3300	Methods and Procedures for Refunding	Volume 1, "Agreement to Refund"
Minn. R. 7825.3500	Proposal for Change in Rates A. Name, address, etc. B. Date of filing and date of modified rates C. Description and purpose of request D. Effect in gross revenue $ and % E. Signature and title of utility officer	Volume 1, Cover letter
Minn. R. 7825.3600	Modified Rate Schedules and Tariffs	Volume 1, Exhibits 17-19
Minn. R. 7825.3700	Expert Opinions and Supporting Exhibits	Volume 1, Testimony and Exhibits 1-19
Minn. R. 7825.3800	Scope and Supplemental Information	See Minn. R. 7825.3900 to 7825.4400 below
Minn. R. 7825.3900	Jurisdictional Financial Summary Schedule A. The proposed rate base, operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the test year. B. The actual unadjusted rate base, unadjusted operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year. C. The projected unadjusted rate base, unadjusted operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.	Volume 1, Exhibit 2

MN Rule	**Description**	**Compliance**
Minn. R. 7825.4000	Rate Base Schedules A. Summary schedule by major rate base component B. Comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component C. Rate Base Adjustments D. Rate Base Assumptions and Approach E. Rate Base Jurisdictional Allocation Factors (for multijurisdictional utilities)	Volume 1, Exhibit 2
Minn. R. 7825.4100	Operating Income Schedules A. Jurisdictional Operating Income Statements B. Total Utility and Jurisdictional Operating Income Statements C. Utility Income Tax Computations (investor-owned utilities) D. Operating Income Adjustments E. Operating Income Assumptions and Approach F. Operating Income Jurisdictional Allocation Factors (for multijurisdictional utilities)	Volume 1, Exhibit 1 and Exhibit 5
Minn. R. 7825.4200	Rate of Return Cost of Capital Schedules A. Rate of Return Summary Schedules B. Supporting Schedules C. Average Short-Term Securities	Volume 1, Exhibit 2
Minn. R. 7825.4300	Rate Structure and Design Information A. Summary Comparison Test Year Operating Revenue B. Detailed Comparison Test Year Operating Revenue C. Cost of Service Study	A. Volume 1, Exhibit 6 B. Volume 1, Exhibit 6 C. Volume 1, Exhibit 3

MN Rule	Description	Compliance
Minn. R. 7825.4400	Other Supplemental Information A. Annual Report B. Gross Revenue Conversion Factor (Investor-Owned) C. Form 7 (cooperatives) D. Form 7A (cooperatives) E. Form 325 Financial Forecast (cooperatives)	A. Volume 2, WP 2 B. NA C. Volume 2, WP 1 D. Volume 2, WP 1 E. Volume 2, WP 5
Minn. R. 7814.2400, subp. 4	New Base Electric Fuel Cost	Volume 1, Exhibit 12
Minn. R. 7829.2400	Filing requiring determination of gross revenue.	
	Brief summary of the filing, sufficient to apprise potentially interested parties of its nature and general content.	Volume 1, Summary of Filing
	A utility filing a general rate change request shall serve copies of the filing on the Department and Residential Utilities Division of the Office of the Attorney General. The utility shall serve the filing or the summary described in subpart 1 on the persons on the applicable general service list and persons who were parties to its last general rate case or incentive plan proceeding.	Volume 1, Cover Letter

MN Statute	**Description**	**Compliance**
Minn. Stat. § 216B.16, subd. 3	Interim Rates	Volume 1, Notice and Petition for Interim Rates, and Interim Rate Schedules
Minn. Stat. § 216B.241 Minn. Stat. § 216B.16, subd. 1	Energy Conservation Improvement Plan	Volume 2, WP 9
Minn. Stat.§ 216B.16, subd.17; Travel, Entertainment and Related Employee Expenses	Schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: (1) travel and lodging expenses; (2) food and beverage expenses; (3) recreational and entertainment expenses; (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (6) dues and expenses for memberships in organizations or clubs; (7) gift expenses; (8) expenses related to owned, leased, or chartered aircraft; and (9) lobbying expenses.	Volume 2, WP 15

Policy Statement	**Description**	**Compliance**
Advertising	Statement that recovery is requested only for permitted advertisements. Description of advertisements for which recovery is requested. Sample advertisements for which recovery is requested.	Volume 2, WP 18
Charitable Contributions	Evidence as to whether the recipients of the contributions: serve the utility's Minnesota service area; are nondiscriminatory in selecting recipients; and do not promote political or special interest groups. Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual. Itemized schedule showing amount, recipient and time of donations. Only 50% of qualified contributions shall be allowed as operating expenses.	Volume 2, WP 19
Organizational Dues	Schedule showing each organization being paid, the number of employees belonging to each organization and the dollar amount of dues being paid to each organization. Testimony explaining the primary purpose of each organization.	Volume 2, WP 20
Research Expenses	Description of each research activity for which an expense is claimed, with all expenses for each activity itemized and supported.	Not Applicable
Cash Working Capital	Lead/lag study with: 1) lead time divided into service to meter reading; meter reading to billing; and billing to collection; and 2) lag expenses divided in categories such as fuel, purchased power, labor. Other issues may include average or minimum cash	Volume 2, WP 6

	balances required, depreciation, dividends and interest on debt.	
Interim Rates	Name, address and telephone number of utility and attorneys. Date of filing and date proposed interim rates are requested to become effective. Description and need for interim rates. Description and corresponding dollar amount change included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues. Certification by officer of the utility. Signature and title of the utility officer authorizing the proposed interim rates. Methods and procedures for refunding. Supporting schedules and work papers. Modified tariffs. Notices.	Volume 1, Notice and Petition for Interim Rates, and Interim Rate Schedules and Volume 1, Transmittal Documents

MPUC Order **E-111/GR-09-175**	**Description**	**Compliance**
Sales Forecast	Dakota Electric shall, in future rate cases, be consistent in its use and source of weather data in determining its sales forecast.	Volume 2, WP 13
Long-Term Interest Expense	Dakota Electric shall, in its next rate case, demonstrate that its long-term interest expense is prudently incurred. Such demonstration shall include data of rates offered by other lenders.	Volume 2, WP 17
Minimum-Size Method	Dakota Electric shall, in its next rate case, either use the minimum-size method to classify distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method.	Volume 2, WP 21
Line Extensions	Regarding line extensions, if Dakota Electric determines that there has been any increase in the number of its overhead extensions, it shall include that information in its next rate case.	Volume 1, DRL Testimony

MPUC Order **E-111/GR-14-482**	**Description**	**Compliance**
Purchased-Power	Dakota Electric Association shall include in the initial filing of its next rate case work papers for both the purchased-power revenue and purchased-power expense amounts included in the pro forma test-year financial schedule.	Volume 2, WP 24
COS Demand Adjustment	Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.	Volume 2, WP 21 and Volume 1, Exhibit 3

Misc. Dockets	**Description**	**Compliance**
E-999/CI-06-159	In an August 10, 2007 Order, the Commission stated its intention to examine individual utility smart metering practices in the context of rate cases.	Volume 2, WP 25
E-111/M-16-774	The Association will track the wholesale power cost credits associated with each Member Specific Discount and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.	Volume 1, Exhibit 12
E-111/M-16-923	The Association will track the wholesale power costs associated with All Large Load High Load Factor credits and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.	Volume 1, Exhibit 12
E-111/M-17-180	The Association will track the wholesale power costs associated with all contract rates and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Commission.	Volume 1, Exhibit 12

Proposed changes for base electricity rates

Dakota Electric Association has asked the Minnesota Public Utilities Commission (MPUC) for permission to increase electric utility rates and service charges. The proposed increase in total cooperative annual revenues will be about $8.7 million or 4.3% overall.

Interim rates

State law allows us to collect higher rates on an interim basis while our rate filing is reviewed. If the MPUC approves our request for $6.0 million or a 3.0% interim increase, the additional charge will apply to electricity use beginning in November, for which members will begin receiving bills in December. This interim increase appears on your bill as "Interim Rate Adjustment." For Residential and Small General Service members, the interim adjustment applies to the monthly fixed charge, energy charge and resource and tax adjustment*. For General Service members the interim adjustment also applies to the demand charge.

The interim increase will remain in effect until the MPUC determines final rates. The MPUC is expected to make its decision in 2020. If the approved overall total increase is lower than interim rates, we will refund members the difference with interest. If the overall total increase is higher, we will not charge members the difference.

What is increasing Dakota Electric's costs?

Since Dakota Electric's last request for a rate increase in 2014, costs for equipment, labor and materials have continued to increase. These factors, combined with minimal growth in electric sales in the last five years, contributed to the need for this filing.

How is Dakota Electric controlling costs?

- Using technology and process improvements to increase efficiency.
- Employees do things every day to reduce expenses. They may not produce large savings on their own but when added together, help lower expenses.
- Offering a variety of programs to help members conserve energy and save money.

Impact on monthly bills

While the effect of the proposed increase on your bill will vary depending upon member classification and amount of energy use, the average monthly bill for a residential member will increase by $4.22 from $94.96 per month to $99.18 per month. The charts below provide more detail on the impact of proposed increases.

Proposed Change in Monthly Electricity Costs

Member classification	Average monthly kWh use	Current monthly bill	Interim monthly bill	Proposed final monthly bill
Residential	700	$94.96	$97.81	$99.18
Small General Service	1,000	$132.90	$136.89	$142.00
General Service	16,000	$1,637	$1,686	$1,654

Energy (per kWh) and Demand (per kW) Rates (including RTA)

Member classification	Current	Proposed
Residential		
Energy: Summer (June - Aug)	13.33¢	13.79¢
Energy: Other (Sept - May)	11.93¢	12.39¢
Small General Service		
Energy: Summer (June - Aug)	12.94¢	13.75¢
Energy: Other	11.54¢	12.35¢
General Service		
Energy: First 200 kWh per kW	8.01¢	7.76¢
Energy: Next 200 kWh per kW	7.01¢	6.76¢
Energy: Over 400 kWh per kW	6.01¢	5.76¢
Demand: Summer (June - Aug)	$12.26	$13.70
Demand: Other (Sept - May)	$9.16	$10.60

Monthly Fixed Charges

Member classification	Current	Proposed
Residential	$9.00	$10.00
Small General Service	$14.00	$15.00
General Service	$34.00	$34.00

*The resource and tax adjustment (RTA) is a periodic rate adjustment for changes in wholesale power costs, property and real estate taxes and conservation spending.

Review process

The Minnesota Public Utilities Commission will hold public hearings and accept written comments about our rate request. The public will be able to comment on our rate request at the public hearings. You may add oral comments, written comments, or both into the record. Dakota Electric will provide details about the hearings in local newspapers, in a bill insert and at www.dakotaelectric.com.

More information

Details about proposed rates are available on Dakota Electric's Web site at www.dakotaelectric.com. A complete copy of our filing is also available for review at our Farmington office between 8 a.m. and 4:30 p.m. Monday through Friday. Our office is located at 4300 220th Street West, Farmington, MN.

You may also examine our current and proposed rate schedules and our request for new rates by contacting the Department of Commerce at:

Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101
Phone: 651-296-9314

Web site: https://www.edockets.state.mn.us/EFiling/search.jsp. Web address is case sensitive. Select 19 in the year field, enter 478 in the number field, click on search and the list of documents will appear on the next page.

Dakota Electric will also keep members informed of rate filing developments in our monthly *Circuits* newsletter and at www.dakotaelectric.com. As always, if you have questions or comments for Dakota Electric, contact us at 651-463-6212 or rates@dakotaelectric.com.

How to participate

Anyone who wishes to formally intervene in this case should contact:

Minnesota Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620
Phone: 651-361-7900

Citizens with hearing or speech disabilities may call through their preferred Telecommunication Relay Service.

You do not need to contact the Minnesota Office of Administrative Hearings if you simply want to attend the public hearings, provide oral comments at the public hearings or submit comment letters.

You may submit written comments to:

Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147
Phone: 651-296-0406 or 800-657-3782
E-mail: consumer.puc@state.mn.us

Citizens with hearing or speech disabilities may call through their preferred Telecommunication Relay Service.

Be sure to reference MPUC Docket No. E-111/GR-19-478 in all correspondence or requests.

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
651-463-6212
www.dakotaelectric.com

Dakota Electric seeks increase in electric rates

Interim rates effective with usage on and after November__, 2019 until final decision is made.

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

4300 220th Street West, Farmington, MN 55024
651-463-6212 • 800-874-3409
www.dakotaelectric.com

Docket No. E-111/GR-19-478

Interim Rate Schedules –
Showing Markup

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	$14.70 per kW
Other	@	$11.10 per kW
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	\$10.10
150 Watt High Pressure Sodium (Closed to new)	\$11.99
250 Watt High Pressure Sodium (Closed to new)	\$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by \$0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than \$0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67
Plus Applicable Taxes	

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44 - 4
LED SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.63 per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 10.60	$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 11.24	$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.31	$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.71	$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

SCHEDULE 46
GENERAL SERVICE

Availability
Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge
The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service
A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.0940 per kWh Plus applicable taxes

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0440 per kWh
Plus Applicable Taxes.		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0550 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
		Plus
Maximum Demand Charge	@	$ 4.75 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.
**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability
Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period
The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand
The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand
The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

INTERIM RATE ADJUSTMENT RIDER

Availability

The 3.0% Interim Rate Adjustment applies to:

1. Fixed Charge
2. Energy Charge
3. Demand Charge
4. Resource and Tax Adjustment
5. Minimum Charges
6. Energy Charge Credits
7. Voltage Discounts
8. Lighting Rates per Luminaire
9. Low Wattage Unmetered Service
10. Standby Reservation Fees
11. Controlled Air Conditioning and Water Heating Discounts

The Interim Rate Adjustment does not apply to:

1. Municipal Civil Defense Sirens
2. Special Fees or Charges
3. Communication Fee
4. Competitive Service Rider
5. Franchise Fee Surcharge Rider
6. Optional Renewable Energy Rider
7. Member Energy Exchange Rider
8. Voluntary Energy Reduction Rider
9. Member Specific Discount Rider
10. Large Load High Load Factor Rider
11. Contract Rate Service
12. Advanced Grid Infrastructure Rider
13. Advanced Meter Opt-Out (AMO) Rider
14. Late Payment Charge

This temporary Interim Rate Adjustment Rider will expire when final rates become effective.

Rate
Each rate schedule that the Interim Rate Adjustment applies to contains the following text:

> Interim Rate Adjustment
> A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November __, 2019.

Docket No. E-111/GR-19-478

Interim Rate Schedules –
Clean

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

<u>Availability</u>
Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

<u>Type of Service</u>
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

<u>Monthly Rate</u>

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

<u>Interim Rate Adjustment</u>
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

<u>Minimum Monthly Charge</u>
The minimum monthly charge under the above rate shall be the Fixed Charge.

<u>Resource and Tax Adjustment (RTA)</u>
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

<u>Taxes</u>
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

<u>Terms of Payment</u>
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	$14.70 per kW
Other	@	$11.10 per kW
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$10.10
150 Watt High Pressure Sodium (Closed to new)	$11.99
250 Watt High Pressure Sodium (Closed to new)	$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67
Plus Applicable Taxes	

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability
Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service
The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44 - 4
LED SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens) $7.63 per month
Plus Applicable Taxes

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 10.60	$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 11.24	$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.31	$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.71	$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

SCHEDULE 46
GENERAL SERVICE

Availability
Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge
The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service
A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.0940 per kWh Plus applicable taxes

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	\$0.0440 per kWh
Plus Applicable Taxes.		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by \$0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than \$0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over \$10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or \$1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0550 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
		Plus
Maximum Demand Charge	@	$ 4.75 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric’s conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association’s total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.
**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability
Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period
The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand
The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand
The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control
The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance
Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

INTERIM RATE ADJUSTMENT RIDER

Availability

The 3.0% Interim Rate Adjustment applies to:

1. Fixed Charge
2. Energy Charge
3. Demand Charge
4. Resource and Tax Adjustment
5. Minimum Charges
6. Energy Charge Credits
7. Voltage Discounts
8. Lighting Rates per Luminaire
9. Low Wattage Unmetered Service
10. Standby Reservation Fees
11. Controlled Air Conditioning and Water Heating Discounts

The Interim Rate Adjustment does not apply to:

1. Municipal Civil Defense Sirens
2. Special Fees or Charges
3. Communication Fee
4. Competitive Service Rider
5. Franchise Fee Surcharge Rider
6. Optional Renewable Energy Rider
7. Member Energy Exchange Rider
8. Voluntary Energy Reduction Rider
9. Member Specific Discount Rider
10. Large Load High Load Factor Rider
11. Contract Rate Service
12. Advanced Grid Infrastructure Rider
13. Advanced Meter Opt-Out (AMO) Rider
14. Late Payment Charge

This temporary Interim Rate Adjustment Rider will expire when final rates become effective.

Rate

Each rate schedule that the Interim Rate Adjustment applies to contains the following text:

> Interim Rate Adjustment
> A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November __, 2019.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matt Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates
for Electric Service in Minnesota

Docket No. E-111/GR-19-478
September 19, 2019

NOTICE AND PETITION FOR INTERIM RATES

A. Introduction

Dakota Electric Association ("Dakota Electric" or "Cooperative") submits to the Minnesota Public Utilities Commission ("MPUC" or the "Commission") this Petition for Interim Rates (the "Petition") for retail electric rates to members, pursuant to Minn. Stat. § 216B.16 subd. 3; the Commission's Statement of Policy on Interim Rates dated April 14, 1982; and relevant Commission rules.

B. Information Provided Pursuant to the Commission Statement of Policy on Interim Rates and Relevant Commission Rules

1. Name, address, and telephone number of utility and attorney.
(Policy Statement, Item 1, page 2)

Utility Filing for Rate Change:
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
(651) 463-6212

Representing Attorney:
Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402-4629
(612) 604-6511

<u>2. Date of filing and date proposed interim rates are requested to become effective.</u>
<u>(Policy Statement, Item 2, page 2)</u>

This Petition is filed September 19, 2019. The Petition is submitted as part of the Cooperative's Application for a General Electric Rate Increase (the "Application"), which is also being filed on September 19, 2019. Pursuant to Minn. Stat. § 216B.16,subd.3, Dakota Electric requests, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. § 216B.16, subd. 2, that the proposed interim rates be made effective with <u>consumption</u> occurring on and after November 18, 2019. The interim rates will be subject to refund, pending final Commission determination on the general electric rate increase.

<u>3. Description and need for interim rates.</u>
<u>(Policy Statement, Item 3, page 2)</u>

Dakota Electric proposes an interim rate increase of three percent (3.0%), which will apply to retail rates as specified in the proposed Interim Rate Adjustment Rider. Interim rates are necessary because the Cooperative has experienced increasing costs of service as reflected in the Cooperative's general rate application. The proposed 3.0% interim rate increase is anticipated to be sufficient to maintain positive annual margins beginning in 2020. We calculated the proposed interim rates consistent with Commission requirements and precedent. Specifically, when determining the interim rate request, the overall rate of return ("ROR") requested for interim rates for Dakota Electric uses the present average cost of long-term debt and the return on equity previously authorized by the Commission in Dakota Electric's last rate case (Docket No. E-111/GR-14-482). The proportion of each component and the factor to adjust the weighted cost of capital to establish return on rate base is also consistent with the numbers approved in the final order from our last general rate case. Overall, this adjustment results in an interim revenue deficiency of about $8,460,000 or about 4.2 percent, which is greater than the requested interim increase of 3.0% and slightly lower than the overall increase of about 4.3% requested in this proceeding.

Minn. Stat. § 216B.16, subd. 3(b) provides that unless "the commission finds that exigent circumstances exist, the interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include (1) a rate of return on common equity for the utility equal to that authorized by the commission in the utility's most recent rate case proceeding."

In calculating interim rates, Dakota Electric proposes an amount that is less than the amount authorized under the interim rates statute, but sufficient to meet financial metrics during the rate case proceeding while providing a transitional step to final rates. As the Commission found in the Cooperative's last two rate case proceedings, charging the Association's members more than the Association believes its operations require for interim rates would contravene the public interest. The Commission has agreed that Dakota Electric's proposed approach to interim revenue increases in past rate cases is reasonable and in the public interest. Therefore, Dakota Electric requests that the Commission find that exigent circumstances exist and not require Dakota Electric to apply the capital structure and cost of capital set by statute when determining the interim rate increase in this rate case. The Association's request avoids collecting more revenue than necessary during this proceeding and provides a transitional increase in rates should the Commission ultimately order the rates requested.

4. Description and corresponding dollar amount of changes included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available. (Policy Statement, Item 4, page 2)

A comparison of the Interim Petition and Application revenue deficiencies is attached to this Petition. The difference in the two calculations relates to the overall rate of return. The Application calculates a ROR of 5.73%, while the Interim Petition uses a 5.59% percent ROR calculated as follows:

Component	Proportion	Cost Rate	Weighted Cost
Long-Term Debt	41.81%	3.77%	1.58%
Return on Equity	58.19%	4.28%	2.49%
Weighted Cost of Capital	100%		4.07%
Return on Rate Base		1.373	5.59%

In any event, Dakota Electric is requesting an interim revenue increase below the revenue deficiency identified in both the Application and Interim Petition calculations.

5. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues. (Policy Statement, Item 5, page 2).

The test year for Dakota Electric's general rate increase filing is the historical 2018 calendar year adjusted for known and measurable changes. Dakota Electric requests an interim rate adjustment that will increase Dakota Electric's base rate (distribution) revenues by about $6,000,000 or 3.0 percent above the test year gross revenues. This interim rate adjustment will be uniformly billed as a 3.0 percent increase on the subtotal of members' bills. As noted, this interim increase is below the possible interim increase of about $8,460,000 calculated according to Commission requirements and precedent for interim adjustments. The proposed Interim Tariff clause describes the interim rate increase and is consistent with the application of interim rates approved by the Commission in Dakota Electric's last two general rate cases (Docket No. E-111/GR-09-175 and Docket No. E-111/GR-14-482). We have further refined that explanation by developing an Interim Rate Surcharge Rider, which lists those charges to which the interim rate increase applies and a list of those rates to which the interim rate increase does not apply. This Rider is identical to the Rider approved by the Commission in our last two general rate cases. Dakota Electric proposes that a uniform percentage be applied to all of the base rate elements listed in the Interim Rate Surcharge Rider, with such interim revenue being used to support our distribution operations. That is, Dakota Electric proposes to continue all present charges, including the RTA, and apply the 3.0

percent interim adjustment to the subtotal of such charges. All such interim revenue will be applied to the Cooperative's provision of electric distribution service.

6. Certification by Chief Executive Officer.
(Policy Statement, Item 6, page 2)

This Petition contains a certificate signed by Greg Miller, President and CEO, Dakota Electric Association, affirming that this interim rate Petition complies with Minnesota Statutes and is attached to this petition.

7. Methods and procedures for refunding.

Pursuant to Minn. Stat. § 216B.16, subd. 3, Dakota Electric's Agreement and Undertaking to make appropriate refunds if required is contained in the Application.

8. Signature and title of the utility officer authorizing the proposed interim rates. (Policy Statement, Item 7, page 2)

The Petition is signed on behalf of Dakota Electric by Greg Miller, President and CEO, Dakota Electric Association.

9. Supporting schedules and workpapers.
(Policy Statement, Items 1-4, page 3)

The supporting documentation described in the Commission's Policy Statement is included with this Petition and Application. These schedules include the rate base amounts; income statement amounts; revenue deficiencies; rates of return required for interim rates as compared to the same information for Dakota Electric's general rate increase Application.

10. Interim rate schedules, Revenue rate comparisons.
(Minn. R. 7825.3600)

A summary of the revenue increases under present and proposed interim rates for all customer classes is included in this Petition. The rate schedules containing proposed interim rates are also included with this Petition. Consistent with Minn. Stat. § 216B.16, subd. 3, no change has been made in the existing rate design. A uniform percentage equal to the proposed interim rate increase needed to recover the interim revenue deficiency from base rates has been applied to all billing components as described in the Interim Rate Adjustment Rider.

11. Customer Notice.
(Minn. R. 7829.2400, subpt. 3; Minn. Stat. § 216B.16, subd. 1)

Pursuant to Minn. R. 7829.2400, subpt. 3, and Minn. Stat. § 216B.16, subd. 3, Dakota Electric proposes to send a notice to its members and to the counties and municipalities in our service area. In addition, Dakota Electric will publish a display advertisement in the newspapers of general circulation in Dakota County. Pursuant to Minn. Stat. § 216B.16, subd. 1, the proposed notice to consumers, counties and municipalities is included in this filing and can be found in the transmittal information in the Application.

12. Interim Bills.

The Commission's Policy Statement on Interim Rates suggests that changes in interim rates be shown on customer bills as a separate line item "if practical." The interim rate amount will be shown as a separate line item stated as "Interim Rate Adjustment," and will reflect the total amount of the interim charge applied to the bill.

C. Conclusion

Dakota Electric respectfully requests, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. 216B.16, subd. 2, that the proposed interim rates be made effective with consumption occurring on and after November 18, 2019, subject to refund, pending final Commission action on the Cooperative's general electric rate increase Application.

Dated: September 19, 2019
Respectfully submitted,

Greg Miller
President & CEO
Dakota Electric Association

Interim Exhibits

Statement of Operations
Present Rates
Test Year - 2018 Historical Adjusted

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Adjustments [1]	(e) Pro Forma Test Year	
1	**Operating Revenue**	($)	($)	($)	
2	Rate Schedules	202,630,477	(2,150,170)	200,480,307	[2]
3	Other	508,198	592,593	1,100,791	
4	**Total Operating Revenue**	203,138,675	(1,557,577)	201,581,098	
5	**Operating Expenses**				
6	Cost of Purchased Power	149,330,034	1,319,432	150,649,466	[3]
7	Transmission - O & M	-		-	
8	Distribution - Operation	7,277,184	(383,045)	6,894,139	
9	Distribution - Maintenance	6,151,338	242,574	6,393,912	
10	Consumer Accounts	5,312,955	380,854	5,693,809	
11	Consumer Service & Information	3,585,760	(180,461)	3,405,299	
12	Sales	-		-	
13	Administrative & General	11,907,838	71,783	11,979,621	
14	Depreciation & Amortization	10,281,975	404,073	10,686,048	
15	Taxes - Property	3,372,283	178,507	3,550,790	
16	Taxes - Other	-		-	
17	Other Interest Expense	549,008		549,008	
18	Other Deductions	6,239	(38,705)	(32,466)	
19	**Total Operating Expenses** (Before Long Term Interest)	197,774,614	1,995,012	199,769,626	
20	**Net Operating Income** (Before Long Term Interest)	5,364,061	(3,552,589)	1,811,472	

[1] The operating expense adjustments are summarized on pages 2 through 10.
[2] See pages 12 through 21 for Pro Forma Test Year Revenue.
[3] See page 22 for Pro Forma Test Year Purchased Power expense.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) 2019 Budget Avg No. Cons. [1]	(d) Energy Sales [2]	(e) Billing Demand [2]	(f) Revenue [3]
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	100,202	838,089,528	N.A.	114,332,035
2	Residential & Farm Demand Control (32)	15	378,000	917.2	42,670
3	Electric Vehicle (33)	88	300,960	N.A.	24,636
4	Irrigation Service (36) Firm	8	162,528	1,867.3	50,143
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	862,089
6	Small General Service (41)	4,431	42,537,600	N.A.	5,799,609
7	Security Lighting Service (44) - Closed to New	878	405,600	N.A.	102,369
8	Street Lighting Service (44-2)	2,269	2,405,280	N.A.	466,293
9	Street Lighting System (44-1)	470	521,040	N.A.	72,603
10	Custom Residential Street Lighting (44-3)	12,190	6,750,960	N.A.	1,334,683
11	LED Security Lighting Service (44 -4)	356	64,896	N.A.	31,109
12	LED Street Lighting Member Owned(44-5)	11	8,712	N.A.	1,297
13	LED Street Lighting (44-6)	597	202,152	N.A.	59,884
14	Low Wattage Unmetered Service (45)	71	-	N.A.	8,520
15	General Service (46)	2,750	462,000,000	1,442,500.4	50,261,766
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	*3*	172,800	N.A.	16,571
18	Controlled Energy Storage (51)	1,718	10,308,000	N.A.	459,736
19	Controlled Interruptible Service (52)	6,686	44,127,600	N.A.	2,634,418
20	Residential & Farm Time of Day (53)	18	216,216	N.A.	29,057
21	General Service Time of Day (54)	6	1,059,984	6,802.3	126,286
22	Standby Service (60)	1	-		66,840
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	23,144,467
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,151,089
25	Cycled Air Conditioning Service (80)	41,880	5,075,000	N.A.	(1,625,193)
26	Wellspring				23,370
27	**Total** [4]	108,165	1,824,313,200	2,496,964.3	200,480,307
28	Actual Revenue Recorded 2018				202,630,477
29	Adjustment				(2,150,170)

[1] Pro Forma Test Year consumers are based on DEA's average number of 2019 budgeted consumers.
[2] Energy Sales are based on average monthly sales using the higher of 7-10 year trend or budget multiplied by average budgeted 2019 number of customers. See Workpaper 13.
[3] See page 13 through 21.
[4] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Determination of Interim
Revenue Requirements - Summary

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Present Rates Pro Forma Test Year	(e) Pro Forma Test Year Interim
	Financial Results From Rates	($)	($)	($)
1	Total Revenue [1]	203,138,675	201,581,098	201,581,098
2	Operating Expense [1]	197,774,614	199,769,626	199,769,626
3	Net Operating Income (before interest expense) [2]	5,364,061	1,811,472	1,811,472
4	Capital Credits [3]	5,111,212	5,111,212	5,111,212
5	Other Non-Operating Income [3]	292,978	292,978	292,978
6	Total Margin (before interest expense) [4]	10,768,251	7,215,662	7,215,662
	Required Increase (Decrease) --ROR Objective			
7	Operating Expense (excluding interest) [1]	197,774,614	199,769,626	199,769,626
8	Margin Requirements			
9	Rate Base [5]	189,064,856	189,064,856	189,064,856
10	Rate of Return [6]	5.73%	5.73%	**5.59%**
11	Required Return [7]	10,831,846	10,831,846	10,568,725
12	Less: Non-Operating Income [3]	292,978	292,978	292,978
13	Net Operating Income Required [8]	10,538,868	10,538,868	10,275,747
14	Total Revenue Requirements [9]	208,313,482	210,308,494	210,045,373
15	Revenue Present Rates			
16	Tariff Revenue [1]	202,630,477	200,480,307	200,480,307
17	Other Operating Revenue [1]	508,198	1,100,791	1,100,791
18	Total Revenue [10]	203,138,675	201,581,098	201,581,098
19	Required Increase (Decrease) [11]	5,174,807	8,727,396	8,464,275
20	Percent Increase (Decrease) [12]	2.55	4.35	4.22

[1] See Exhibit__(DEA-1).
[2] Line 1 minus Line 2.
[3] See Workpaper 3.
[4] Line 3 plus Line 4 plus Line 5.
[5] See Exhibit__(DEA-2), page 2.
[6] See Exhibit__(DEA-2), page 5.
[7] Line 9 times Line 10.
[8] Line 11 minus Line 12.
[9] Line 7 plus Line 13.
[10] Line 16 plus Line 17.
[11] Line 14 minus Line 18.
[12] Line 19 divided by Line 16.

Rate Base

(a) Line No.	(b) Description	(c) Proposed Pro Forma Test Year
		($)
1	Utility Plant in Service [1]	300,342,133
2	Construction Work in Progress [1]	4,222,209
3	Less: Accumulated Provision for Deprec. [2]	126,526,023
4	Net Plant [1]	178,038,319
5	Materials & Supplies - Electric [3]	4,715,491
6	Working Capital [4]	6,816,147
7	Subtotal	11,531,638
8	Less: Consumer Deposits [1]	505,101
9	**Total Rate Base**	189,064,856

[1] December 31, 2018 Form 7 amount. See Workpaper 1.

[2] December 31, 2018 Form 7 amount adjusted to include Depreciation adjustment . See Exhibit _ (DEA-1), page x.

[3] Thirteen - month average. See Exhibit__(DEA-2), page 3.

Rate Base Calculations
Materials & Supplies

(a) Line No.	(b) Month		(c) Materials & Supplies Electric [1]
			($)
1	Dec	2017	4,472,686
2	Jan	2018	4,649,607
3	Feb	2018	4,676,986
4	Mar	2018	4,753,122
5	Apr	2018	4,953,466
6	May	2018	5,128,406
7	Jun	2018	4,907,896
8	Jul	2018	5,020,268
9	Aug	2018	4,854,970
10	Sep	2018	4,612,252
11	Oct	2018	4,752,223
12	Nov	2018	4,335,261
13	Dec	2018	4,184,242
14	**Total**		61,301,385
15	**13 - Month Average**		4,715,491

[1] Inventory accounts 13110 through 13320 from December 31, 2018 year end General Ledger.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

II. Consumer and Sales Data for Pro Forma Test Year

(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**2019 Budget Avg No. Cons.** [1]	**Energy Sales** [2]	**Billing Demand** [2]	**Revenue** [3]
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	100,202	838,089,528	N/A	117,761,996
2	Residential & Farm Demand Control (32)	15	378,000	917.2	43,950
3	Electric Vehicle (33)	88	300,960	N/A	25,375
4	Irrigation Service (36) Firm	8	162,528	1,867.3	51,647
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	887,952
6	Small General Service (41)	4,431	42,537,600	N/A	5,973,597
7	Security Lighting Service (44) - Closed to New	*831*	405,600	N/A	105,440
8	Street Lighting Service (44-2)	*2,285*	2,405,280	N/A	480,282
9	Street Lighting System (44-1)	*487*	521,040	N/A	74,781
10	Custom Residential Street Lighting (44-3)	*12,233*	6,750,960	N/A	1,374,723
11	LED Security Lighting Service (44 -4)	*338*	64,896	N/A	32,042
12	LED Street Lighting Member Owned(44-5)	*11*	8,712	N/A	1,336
13	LED Street Lighting (44-6)	*521*	202,152	N/A	61,681
14	Low Wattage Unmetered Service (45)	71		N/A	8,776
15	General Service (46)	2,750	462,000,000	1,442,500.4	51,769,619
16	Municipal Civil Defense Sirens (47)	66	-	N/A	3,960
17	Geothermal Heat Pump (49) Closed to New		172,800	N/A	17,068
18	Controlled Energy Storage (51)	*1,718*	10,308,000	N/A	473,528
19	Controlled Interruptible Service (52)	*6,686*	44,127,600	N/A	2,713,451
20	Residential & Farm Time of Day (53)	18	216,216	N/A	29,929
21	General Service Time of Day (54)	6	1,059,984	6,802.3	130,075
22	Standby Service (60)	1			68,845
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	23,838,641
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,215,568
25	Cycled Air Conditioning Service (80)	*41,880*		N/A	(1,673,949)
26	**Total** [4]	108,165	1,824,313,200	2,496,964.3	206,470,312

[1] Pro Forma Test Year consumers are based on DEA's average number of 2019 budgeted consumers.
[2] Energy Sales are based on average monthly sales using the higher of 7-10 year trend or budget multiplied by average budgeted 2019 number of customers. See Workpaper 13.
[3] See pages 13 through 21.
[4] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units		Rate	Revenue
Residential & Farm Service (31)					($)
Fixed Charge	100,202	cons.	$	9.00	10,821,816
Energy Charge					
Summer	257,025,312	kWh	$	0.13080	33,618,911
Other	581,064,216	kWh	$	0.11680	67,868,300
RTA Charge [1]	838,089,528	kWh	$	0.00250	2,095,224
Controlled Water Heater Credit	1,003	units		($6.00)	(72,216)
			Subtotal		114,332,035
Interim Rate Adjustment				3.0%	3,429,961
			Total		117,761,996
Residential & Farm Demand Control (32)					
Fixed Charge	15	cons.	$	12.00	2,160
Demand Charge					
Summer	182.2	kW	$	14.70	2,678
Other	735.0	kW	$	11.10	8,159
Energy Charge	378,000	kWh	$	0.07600	28,728
RTA Charge [1]	378,000	kWh	$	0.00250	945
			Subtotal		42,670
Interim Rate Adjustment				3.0%	1,280
			Total		43,950
Electric Vehicle (33)					
Energy Charge					
Off Peak	280,402	kWh	$	0.06740	18,899
On Peak	8,554	kWh	$	0.41440	3,545
Other					
Summer	2,693	kWh	$	0.13080	352
Other	9,311	kWh	$	0.11680	1,088
RTA Charge [1]	300,960	kWh	$	0.00250	752
			Subtotal		24,636
Interim Rate Adjustment				3.0%	739
			Total		25,375
Irrigation Service (36)					
Firm Service					
Fixed Charge	8	cons.	$	30.00	2,880
Demand Charge					
Summer	902.3	kW	$	26.35	23,776
Winter	2.5	kW	$	20.95	52
Other	962.5	kW	$	15.50	14,919
Energy Charge	162,528	kWh	$	0.04990	8,110
RTA Charge [1]	162,528	kWh	$	0.00250	406
			Subtotal		50,143
Interim Rate Adjustment				3.0%	1,504
			Total		51,647

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Irrigation Service (36)				
Interruptible Service				
Fixed Charge	384	cons.	$ 30.00	138,240
Demand Charge	74,388	kW	$ 4.55	338,463
Energy Charge	7,801,344	kWh	$ 0.04990	389,287
RTA Charge [1]	7,801,344	kWh	$ (0.00050)	(3,901)
			Subtotal	862,089
Interim Rate Adjustment			3.0%	25,863
			Total	887,952
Small General Service (41)				
Fixed Charge	4,431	cons.	$ 14.00	744,408
Energy Charge				
Summer	10,541,910	kWh	$ 0.12690	1,337,768
Other	31,995,690	kWh	$ 0.11290	3,612,313
RTA Charge [1]	42,537,600	kWh	$ 0.00250	106,344
Controlled Water Heater Credit	17	units	$ (6.00)	(1,224)
			Subtotal	5,799,609
Interim Rate Adjustment			3.0%	173,988
			Total	5,973,597
Security Lighting Service (44)				
175 W MV	0	lights	N/A	0
100 W HPS	819	lights	$ 10.10	99,263
150 W HPS	4	lights	$ 11.99	576
250 W HPS	8	lights	$ 15.79	1,516
RTA Charge [1]	405,600	kWh	$ 0.00250	1,014
			Subtotal	102,369
Interim Rate Adjustment			3.0%	3,071
			Total	105,440
Street Lighting Service (44-2)				($)
175 W MV	-	lights	$ 15.23	0
250 W MV	3	lights	$ 18.16	654
400 W MV	-	lights	$ 23.25	0
100 W HPS	38	lights	$ 12.27	5,595
150 W HPS	646	lights	$ 14.16	109,768
250 W HPS	1,597	lights	$ 17.95	343,994
400 W HPS	1	lights	$ 22.38	269
RTA Charge [1]	2,405,280	kWh	$ 0.00250	6,013
			Subtotal	466,293
Interim Rate Adjustment			3.0%	13,989
			Total	480,282

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units		Rate	Revenue
					($)
Street Lighting System (44-1)					
175 W MV	-	lights	$	10.52	0
250 W MV	-	lights	$	13.46	0
400 W MV	-	lights	$	18.54	0
100 W HPS	-	lights	$	7.56	0
150 W HPS	101	lights	$	9.46	11,466
200 W HPS	101	lights	$	11.41	13,829
250 W HPS	272	lights	$	13.25	43,248
400 W HPS	13	lights	$	17.67	2,757
RTA Charge [1]	521,040	kWh	$	0.00250	1,303
			Subtotal		72,603
Interim Rate Adjustment				3.0%	2,178
			Total		74,781
Custom Residential Street Lighting (44-3)					
175 W MV	-	lights	$	11.37	0
50 W HPS	81	lights	$	6.70	6,512
100 W HPS	8,416	lights	$	8.41	849,343
150 W HPS	3,732	lights	$	10.30	461,275
250 W HPS	4	lights	$	14.09	676
RTA Charge [1]	6,750,960	kWh	$	0.00250	16,877
			Subtotal		1,334,683
Interim Rate Adjustment				3.0%	40,040
			Total		1,374,723
LED Security Lighting (44-4)					
LED, >4,500 Lumens	338	lights	$	7.63	30,947
RTA Charge [1]	64,896	kWh	$	0.00250	162
			Subtotal		31,109
Interim Rate Adjustment				3.0%	933
			Total		32,042

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
LED Street Lighting Member Owned(44-5)				
A (40-80 watts)	-	lights	$ 4.81	-
B (81-150 watts)	-	lights	$ 6.71	-
C (151-250 watts)	11	lights	$ 9.66	1,275
D (251-350 watts)	-	lights	$ 13.05	-
E (351-450 watts)	-	lights	$ 16.52	-
RTA Charge [1]	8,712	kWh	$ 0.00250	22
			Subtotal	1,297
Interim Rate Adjustment			3.0%	39
			Total	1,336
LED Street Lighting (44-6)				
Standard				
>5,200 L, Coach (Post)	121	lights	$ 10.60	15,391
>5,200 L, Acorn (Post)	48	lights	$ 11.24	6,474
>7,000 L, Cobra (Mast)	91	lights	$ 8.31	9,075
>11,500 L, Shoebox	151	lights	$ 10.71	19,407
Basic				
>5,200 L, Coach (Post)	41	lights	$ 6.83	3,360
>5,200 L, Acorn (Post)	-	lights	$ 6.30	-
>7,000 L, Cobra (Mast)	53	lights	$ 6.51	4,140
>11,500 L, Shoebox	16	lights	$ 7.98	1,532
RTA Charge [1]	202,152	kWh	$ 0.00250	505
			Subtotal	59,884
Interim Rate Adjustment			3.0%	1,797
			Total	61,681

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units		Rate	Revenue
					($)
Low Wattage Unmetered Service (45)					
Fixed Charge	71	cons.	$	10.00	8,520
Interim Rate Adjustment				3.0%	256
			Total		8,776
General Service (46)					
Fixed Charge	2,750	cons.	$	34.00	1,122,000
Demand Charge					
Summer	413,627.7	kW	$	12.26	5,071,076
Other	1,028,872.7	kW	$	9.16	9,424,474
Energy Charge					
First 200 kWh/kW	264,418,387	kWh	$	0.07760	20,518,867
Next 200 kWh/kW	158,964,776	kWh	$	0.06760	10,746,019
Over 400 kWh/kW	38,616,837	kWh	$	0.05760	2,224,330
Discounts					
Primary Voltage					
Primary Metering					
RTA Charge [1]	462,000,000		$	0.00250	1,155,000
			Subtotal		50,261,766
Interim Rate Adjustment				3.0%	1,507,853
			Total		51,769,619
Municipal Civil Defense Sirens (47)					
Fixed Charge	66	cons.	$	5.00	3,960
Geothermal Heat Pump (49)					
Energy Charge	172,800	kWh	$	0.09400	16,243
RTA Charge [1]	172,800	kWh	$	0.00190	328
			Subtotal		16,571
Interim Rate Adjustment				3.0%	497
			Total		17,068
Controlled Off-Peak Space & Energy Storage (51)					
Energy Net Charge - Rate 31					
Summer	2,701,434	kWh	$	0.04400	118,863
Other	7,509,011	kWh	$	0.04400	330,396
Energy Charge - Rate 41		kWh			
Summer	6,874.0	kWh	$	0.04400	302
Other	39,232.0	kWh	$	0.04400	1,726
Energy Charge - Rate 46	51,449	kWh	$	0.04400	2,264
RTA Charge [1]	10,308,000	kWh	$	0.00060	6,185
			Subtotal		459,736
Interim Rate Adjustment				3.0%	13,792
			Total		473,528

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Interruptible Heating Service (52)				
Energy Net Charge - Rate 31				
Summer	10,488,495	kWh	$ 0.05500	576,867
Other	32,538,130	kWh	$ 0.05500	1,789,597
Energy Charge - Rate 41				
Summer	64,095.0	kWh	$ 0.05500	3,525
Other	386,791.0	kWh	$ 0.05500	21,274
Energy Charge - Rate 46	650,089	kWh	$ 0.05500	35,755
RTA Charge [1]	44,127,600	kWh	$ 0.00470	207,400
			Subtotal	2,634,418
Interim Rate Adjustment			3.0%	79,033
			Total	2,713,451
Residential & Farm Time of Use (53)				
Fixed Charge	18	cons.	$ 12.00	2,592
Energy Charge				
Peak Period				
Summer	49,267	kWh	$ 0.18800	9,262
Other	12,117	kWh	$ 0.17400	2,108
Off-Peak Period	154,832	kWh	$ 0.09400	14,554
RTA Charge [1]	216,216	kWh	$ 0.00250	541
			Subtotal	29,057
Interim Rate Adjustment			3.0%	872
			Total	29,929
General Service Time of Use (54)				
Fixed Charge	6	cons.	$36.00	2,592
Demand Charge				
Peak Period				
Summer	960.1	kW	$24.85	23,858
Winter	436.9	kW	$18.95	8,279
Other	1,253.2	kW	$13.00	16,292
Maximum	4,152.1	kW	$4.75	19,722
Energy Charge	1,059,984	kWh	$0.04990	52,893
Discounts				
Primary Voltage	-	kW	($0.15)	
Primary Metering			(2.0%)	
RTA Charge [1]	1,059,984	kWh	$0.00250	2,650
			Subtotal	126,286
Interim Rate Adjustment			3.0%	3,789
			Total	130,075

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units		Rate	Revenue
					($)
Standby Service Large Power General (60)					
Generation Reservation Fee					
Summer	1,000	kW	$	3.21	9,630
Winter	1,000	kW	$	2.47	7,410
Other	1,000		$	1.74	10,440
Distribution Reservation Fee					
Primary	1,000	kW	$	3.28	39,360
Secondary		kW	$	3.51	0
					66,840
Interim Rate Adjustment				3.0%	2,005
			Total		68,845
Full Interruptible Service (70)					
Fixed Charge	234	cons.	$	110.00	308,880
Communication Fee	51		$	8.70	5,324
Coinc. Demand Charge					
Summer	1,042.8	kW	$	24.85	25,914
Winter	-	kW	$	18.95	0
Other	-	kW	$	13.00	0
Total Coinc Demand	1,042.80	kW	$	-	
Non-Coinc. Demand	858,880.1	kW	$	4.75	4,079,680
Failure to Control	1,042.8	kW	$	5.00	5,214
Energy Charge	379,080,000	kWh	$	0.05	18,916,092
Discounts					
Primary Voltage	47,311	kW	$	(0.15)	($7,097)
Primary Metering	0			-2.0%	$0
RTA Charge [1]	379,080,000	kWh		(0.00050)	(189,540)
			Subtotal		23,144,467
Interim Rate Adjustment				3.0%	694,174
			Total		23,838,641

[1] 2019 applied RTA.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Interim Rates
(Continued)

III. Estimate of Revenue Under Interim Rates

Rate Class	Billing Determinants	Units		Rate	Revenue
					($)
Partial Interruptible Service (71)					
Fixed Charge	28	cons.		$110.00	36,960
Communication Fee	17	cons.		$8.70	1,775
Coinc. Demand Charge					
Summer	3,212.2	kW	$	24.85	79,823
Winter	2,980.2	kW	$	18.95	56,475
Other	5,964.3	kW	$	13.00	77,536
Total Coinc Demand	12,156.7	kW	$	-	
Non-Coinc. Demand	111,609.5	kW	$	4.75	530,145
Excess Demand	0.0	kW	$	5.00	0
Energy Charge	27,720,000	kWh	$	0.05	1,383,228
Discounts	0				
Primary Voltage	6,623	kW	$	0.15	(993)
Primary Metering	0			2.00%	-
RTA Charge [1]	27,720,000	kWh	$	(0.00050)	(13,860)
			Subtotal		2,151,089
Interim Rate Adjustment				3.0%	64,479
			Total		2,215,568
Controlled Air Conditioning Service (80)					
Option 1		kWh		$0.00	0
Option 2					
Residential Rate 81/31	4,858,654	kWh	$	(0.03200)	(155,477)
Rate 81/41	216,346	kWh	$	(0.03200)	(6,923)
Rate 81/46	0	kWh	$	(0.03200)	0
	5,075,000	kWh			(162,400)
Option 3					
Residential Rate 82/31	35,158	cons.	$	(13.00)	(1,371,162)
Commercial	0	cons.	$	(13.00)	0
	35,158				(1,371,162)
Option 4					
Rate 84/41	4,699	tons	$	(6.50)	(91,631)
Rate 84/46	0	tons	$	(6.50)	0
	4,699				(91,631)
			Subtotal		(1,625,193)
Interim Rate Adjustment				3.0%	(48,756)
			Total		(1,673,949)
Grand Total	1,824,313,200				206,470,312

[1] 2019 applied RTA.

Comparison of Revenue
Present and Interim Rates
(Continued)

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates	(d) Revenue Interim Rates	(e) Increase (Decrease) Amount	(f) Percent
		($)	($)	($)	(%)
1	Residential & Farm Service (31)	114,332,035	117,761,996	3,429,961	3.00
2	Residential & Farm Demand Control (32)	42,670	43,950	1,280	3.00
3	Electric Vehicle (33)	24,636	25,375	739	3.00
3	Irrigation Service (36) Firm	50,143	51,647	1,504	3.00
4	Irrigation Service (36) Interruptible	862,089	887,952	25,863	3.00
5	Small General Service (41)	5,799,609	5,973,597	173,988	3.00
6	Security Lighting Service (44) - Closed to New	102,369	105,440	3,071	3.00
7	Street Lighting Service (44-2)	466,293	480,282	13,989	3.00
8	Street Lighting System (44-1)	72,603	74,781	2,178	3.00
9	Custom Residential Street Lighting (44-3)	1,334,683	1,374,723	40,040	3.00
10	LED Security Lighting Service (44 -4)	31,109	32,042	933	3.00
11	LED Street Lighting Member Owned(44-5)	1,297	1,336	39	3.00
12	LED Street Lighting (44-6)	59,884	61,681	1,797	3.00
13	Low Wattage Unmetered Service (45)	8,520	8,776	256	3.00
14	General Service (46)	50,261,766	51,769,619	1,507,853	3.00
15	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
16	Geothermal Heat Pump (49) Closed to New	16,571	17,068	497	3.00
17	Controlled Energy Storage (51)	459,736	473,528	13,792	3.00
18	Controlled Interruptible Service (52)	2,634,418	2,713,451	79,033	3.00
19	Residential & Farm Time of Day (53)	29,057	29,929	872	3.00
20	General Service Time of Day (54)	126,286	130,075	3,789	3.00
21	Standby Service (60)	66,840	68,845	2,005	3.00
22	Full Interruptible Service (70)	23,144,467	23,838,641	694,174	3.00
23	Partial Interruptible Service (71)	2,151,089	2,215,568	64,479	3.00
24	Cycled Air Conditioning Service (80)	(1,625,193)	(1,673,949)	(48,756)	3.00
25	**Total**	200,456,937	206,470,312	6,013,375	3.00

Docket No. E-111/GR-19-478

Exhibit__(DEA-19)
Proposed Rate Schedules

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

COREY HINTZ. . . . . VICE PRESIDENT FINANCIAL SERVICES / CFO

BETTY JO KIESOW . . . . VICE PRESIDENT ENGINEERING SERVICES

JEFF SCHOENECKER. . . . . VICE PRESIDENT UTILITY SERVICES

MJYKE NELSON. . . . . VICE PRESIDENT INFORMATION SERVICES / CIO

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 3
Farmington, MN 55024	REVISION: 17

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to individually metered apartment units and master-metered multi-tenant residential facilities. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$10.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1379 per kWh
Other	@	$0.1239 per kWh
Plus Applicable Taxes		

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Billing for Master-Metered Multi-Tenant Residential Facilities

The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master meter times the Fixed Charge and include the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charge		$ 0.0810 per kWh
Demand Charge		
Summer (June-Aug)	@	$15.50 per kW
Other	@	$11.90 per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0939 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	$0.0756 per kWh
On-Peak:	$0.4421 per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 4.1
Farmington, MN 55024	REVISION: 2

SCHEDULE EV-1
RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service		
Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.60 per kW
Winter (Dec-Feb)	@	$21.20 per kW
Other	@	$15.67 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		
Interruptible		
Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements

Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.0521 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 6.0
REVISION: 9

SCHEDULE 41
SMALL GENERAL SERVICE

Availability

Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$15.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1375 per kWh
Other	@	$0.1235 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option

This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$12.01
150 Watt High Pressure Sodium (Closed to new)	$14.26
250 Watt High Pressure Sodium (Closed to new)	$18.83
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$13.25
250 Watt Mercury (Closed to new)	$16.74
400 Watt Mercury (Closed to new)	$22.71
100 Watt High Pressure Sodium	$9.61
150 Watt High Pressure Sodium	$11.78
200 Watt High Pressure Sodium	$14.18
250 Watt High Pressure Sodium	$16.35
400 Watt High Pressure Sodium	$21.24

Plus Applicable Taxes

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 11.2
Farmington, MN 55024	REVISION: 15

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$17.44
250 Watt Mercury (Closed to new)	$20.93
400 Watt Mercury (Closed to new)	$26.89
100 Watt High Pressure Sodium (Closed to new)	$13.80
150 Watt High Pressure Sodium (Closed to new)	$15.97
250 Watt High Pressure Sodium (Closed to new)	$20.54
400 Watt High Pressure Sodium (Closed to new)	$25.42
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$14.03
50 Watt High Pressure Sodium (Closed to new)	$8.45
100 Watt High Pressure Sodium (Closed to new)	$10.39
150 Watt High Pressure Sodium (Closed to new)	$12.63
250 Watt High Pressure Sodium (Closed to new)	$17.21
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.75 per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: 1

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$5.50
B (81 to 150 watts)	$7.75
C (151 to 250 watts)	$11.16
D (251 to 350 watts)	$15.04
E (351 to 450 watts)	$19.07

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.2
REVISION: 1

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.3
REVISION: 3

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 9.30	$6.36
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 10.85	$6.12
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.60	$6.98
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.70	$8.68
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a "life of fixture" designation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability

This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service

Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges

The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate

$10.50 per month per service location, plus applicable sales tax.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any non-residential member for general service uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$13.70 per kW
Other (Sept – May)	@	$10.60 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt. In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 46
GENERAL SERVICE
(Continued)

Billing for Multi-Use Facilities

Multi-use facilities are defined as buildings or complexes that include a combination of commercial or institutional load along with some portion of residential domestic consumption. (For combined billing, commercial use does not include consumption in common areas of multi-tenant residential facilities.) Where service and metering are separated between residential and commercial consumption, such electrical service will be billed under the terms of Schedule 31, Schedule 41, and Schedules 46 or 54 as applicable. Where such service is combined, such electrical service will be billed under the terms of Schedules 46 or 54 as applicable.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged a reconnect fee as well as the monthly fixed charge for all 12 months.

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability

This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service

Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges

The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate

$5.00/Month per Installation
Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.1030 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0813 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 19.1
REVISION: 4

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service
If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0487 per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0204 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0631 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0352 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.21263 per kWh
Other – Peak Period	@	$0.19863 per kWh
Off-Peak Period	@	$0.09450 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION:	V
4300 220th Street West	SHEET:	24.0
Farmington, Minnesota 55024	REVISION:	14

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$26.14 per kW
Winter (Dec-Feb)	@	$19.91 per kW
Other	@	$13.67 per kW
		Plus
Maximum Demand Charge	@	$ 5.25 per kW
Energy Charge	@	$0.0521 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2890 per kWh
Winter – (Dec-Feb)	@	$0.2320 per kWh
Spring/Fall	@	$0.1880 per kWh
Intermediate Period	@	$0.1060 per kWh
Off-Peak Period	@	$0.0820 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems*.

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$4.02	$4.02
Distribution - Primary Service	$3.89	$3.89
Distribution - Substation Service	$0.81	$0.81

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$26.14 per kW
Winter (Dec-Feb)	@	$19.91 per kW
Other	@	$13.67 per kW
Non-Coincidental Demand	@	$ 5.25 per kW
Energy Charge	@	$0.0521 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

Minimum Billing Demand

The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment

The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$26.14 per kW
Winter (Dec – Feb)	@	$19.91 per kW
Other	@	$13.67 per kW
Non-Coincidental Demand	@	$ 5.25 per kW
Energy Charge	@	$0.0521 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge
The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August (prorated based on the number of qualifying calendar days in the billing month). In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase $95.00
   Three Phase $110.00

2. Bad Check $11.50

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours $55.00
      2) Outside normal working hours...$145.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours $185.00
      2) Outside normal working hours...$340.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck...$340.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours…………………………………………………….$80.00
      2) Outside normal working hours………………………………….$160.00

6. Pulse Meter (materials and installation) $750.00

7. Transfer/Connection Charge $17.50

8. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: VI
SHEET: 3
REVISION: 4

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way corridor to be cleared is 30 feet with no less than 10 feet of clearance to any open or bare wire.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a flat fee of $1,000.00 plus $11.00 per foot of line extension. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation. In no event will the member be charged more than the actual costs for the extension.
2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.
3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.
4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative's equipment.
5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.
6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.
7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment Facilities, and Seasonal Accounts

1. Dakota Electric Association will provide single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and multi-tenant residential facilities in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the primary service to a point of connection designated as either a single-phase or three-phase transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows for service provided under the applicable rate schedule:

	Sched. 31 Factor	Sched. 41 Factor	Sched. 46 Factors	Sched. 70/71 Factors
Estimated Extension Costs				
- Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	NA	$10.09	$10.61
- Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	NA	$0.15958	$0.03157	$.02529
- Credit per Residential Unit times number of residential units in the complex	$1,282	NA	NA	NA
= Required Contribution in Aid of Construction				

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

Docket No. E-111/GR-19-478

Exhibit__(DEA-18)
Blackline Mark-up of
Present Rate Schedules

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

~~LOU ANN WEFLEN~~COREY HINTZ. . . . . VICE PRESIDENT FINANCIAL~~ & INFORMATION~~ SERVICES / CFO

~~RANDY POULSON~~BETTY JO KIESOW . . . . VICE PRESIDENT ENGINEERING SERVICES

~~DIRK ROTTY~~JEFF SCHOENECKER. . . . . VICE PRESIDENT UTILITY SERVICES

MJYKE NELSON…………………………..………. VICE PRESIDENT INFORMATION SERVICES / CIO

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 2
Farmington, MN 55024	REVISION: 13~~2~~

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3
REVISION: 17~~6~~

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to individually metered apartment units and master-metered multi-tenant residential facilities. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$10~~9~~.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1379~~08~~ per kWh
Other	@	$0.1239~~168~~ per kWh
Plus Applicable Taxes		

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Billing for Master-Metered Multi-Tenant Residential Facilities

The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master meter times the Fixed Charge and include the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3.5
REVISION: 9~~8~~

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charge		$ 0.081~~76~~0 per kWh
Demand Charge		
Summer (June-Aug)	@	$15.50~~4.70~~ per kW
Other	@	$11.90~~10~~ per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 4.0
REVISION: 2~~1~~

SCHEDULE EV-1
~~PILOT~~ RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

~~Term~~

~~The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.~~

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	~~6.74¢~~$0.0756 per kWh
On-Peak:	~~41.44¢~~$0.4421 per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 4.1
REVISION: 2~~1~~

SCHEDULE EV-1
~~PILOT~~ RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 5.0
REVISION: 17~~6~~

SCHEDULE 36
IRRIGATION SERVICE

Availability
Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.60~~35~~ per kW
Winter (Dec-Feb)	@	$21.20~~0.95~~ per kW
Other	@	$15.67~~50~~ per kW
Energy Charge	@	$0.0521~~499~~ per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0521~~499~~ per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements
Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.~~0497~~ 0521 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 6.0
REVISION: 9~~8~~

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$15~~4~~.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1375~~269~~ per kWh
Other	@	$0.1235~~129~~ per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 11.0
REVISION: 18~~7~~

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability
Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$12.01~~0.10~~
150 Watt High Pressure Sodium (Closed to new)	$14.26~~1.99~~
250 Watt High Pressure Sodium (Closed to new)	$18.83~~5.79~~
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$13.25~~0.52~~
250 Watt Mercury (Closed to new)	$16.74~~3.46~~
400 Watt Mercury (Closed to new)	$22.71~~18.54~~
100 Watt High Pressure Sodium	$9.61~~7.56~~
150 Watt High Pressure Sodium	$11.78~~9.46~~
200 Watt High Pressure Sodium	$14.18~~1.41~~
250 Watt High Pressure Sodium	$16.35~~3.25~~
400 Watt High Pressure Sodium	$21.24~~17.67~~
Plus Applicable Taxes	

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 11.2
REVISION: 15~~4~~

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$17.44~~5.23~~
250 Watt Mercury (Closed to new)	$20.93~~18.16~~
400 Watt Mercury (Closed to new)	$26.89~~3.25~~
100 Watt High Pressure Sodium (Closed to new)	$13.80~~2.27~~
150 Watt High Pressure Sodium (Closed to new)	$15.97~~4.16~~
250 Watt High Pressure Sodium (Closed to new)	$20.54~~17.95~~
400 Watt High Pressure Sodium (Closed to new)	$25.42~~2.38~~

Plus Applicable Taxes

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 201~~4~~9. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$14.03~~1.37~~
50 Watt High Pressure Sodium (Closed to new)	$8.45~~6.70~~
100 Watt High Pressure Sodium (Closed to new)	$10.39~~8.41~~
150 Watt High Pressure Sodium (Closed to new)	$12.63~~0.30~~
250 Watt High Pressure Sodium (Closed to new)	$17.21~~4.09~~
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 201~~4~~9. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.0
REVISION: 2~~1~~

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens) $7.75~~63~~ per month
Plus Applicable Taxes

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: ~~Original~~1

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$5.50~~4.81~~
B (81 to 150 watts)	$7.75~~6.71~~
C (151 to 250 watts)	$11.16~~9.66~~
D (251 to 350 watts)	$15.04~~13.05~~
E (351 to 450 watts)	$19.07~~16.52~~

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.3
REVISION: 3~~2~~

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 9.30~~10.60~~	$6.36~~83~~
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 10.85~~1.24~~	$6.12~~30~~
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.60~~31~~	$6.98~~51~~
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.70~~1~~	$8.68~~7.98~~
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.4
REVISION: 2~~1~~

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a "life of fixture" designation.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220TH Street West
Farmington, MN 55024

SECTION: V
SHEET: 15
REVISION: 4~~3~~

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.50~~00~~ per month per service location, plus applicable sales tax.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 16.0
REVISION: 4~~3~~

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any ~~commercial~~ non-residential member for ~~all~~ general service uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$13.70~~2.26~~ per kW
Other (Sept – May)	@	$ 10.60~~9.16~~ per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of ~~Metered~~ Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt. In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 16.1
REVISION: 4~~3~~

SCHEDULE 46
GENERAL SERVICE
(Continued)

Billing for Multi-Use Facilities
Multi-use facilities are defined as buildings or complexes that include a combination of commercial or institutional load along with some portion of residential domestic consumption. (For combined billing, commercial use does not include consumption in common areas of multi-tenant residential facilities.) Where service and metering are separated between residential and commercial consumption, such electrical service will be billed under the terms of Schedule 31, Schedule 41, and Schedules 46 or 54 as applicable. Where such service is combined, such electrical service will be billed under the terms of Schedules 46 or 54 as applicable.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged ~~a disconnect and~~ a reconnect fee as well as the monthly fixed charge for all 12 months.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 18
REVISION: 6~~5~~

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability
This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate
$5.00/Month per Installation
Plus Applicable Taxes

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.103~~094~~0 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.~~0775~~ 0813 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 19.1
REVISION: 4~~3~~

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service

If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 21
REVISION: 17~~6~~

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability

Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0487~~40~~ per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.~~0200~~ 0204 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand

The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes

The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 22
REVISION: 17~~6~~

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	\$0.0631~~550~~ per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of \$1.50 per 100 kWh used up to a maximum of \$6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by \$0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than \$0.~~0305~~ 0352 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over \$10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or \$1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, Minnesota 55024

SECTION: V
SHEET: 23.0
REVISION: 11~~0~~

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.21263~~1880~~ per kWh
Other – Peak Period	@	$0.19863~~1740~~ per kWh
Off-Peak Period	@	$0.0945~~40~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION:	V
4300 220th Street West	SHEET:	24.0
Farmington, Minnesota 55024	REVISION:	14~~3~~

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec-Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
		Plus
Maximum Demand Charge	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$0.0521~~499~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 24.1
REVISION: 10~~9~~

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, Minnesota 55024

SECTION: V
SHEET: 25.0
REVISION: ~~Orig~~ 1

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$13~~2~~.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2890~~710~~ per kWh
Winter – (Dec-Feb)	@	$0.2320~~210~~ per kWh
Spring/Fall	@	$0.1880~~750~~ per kWh
Intermediate Period	@	$0.1060~~0970~~ per kWh
Off-Peak Period	@	$0.0820~~760~~ per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.~~0903~~ 0939 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 31.1
Farmington, Minnesota 55024	REVISION: 6~~5~~

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$4.02~~3.51~~	$4.02~~3.51~~
Distribution - Primary Service	$3.89~~28~~	$3.89~~28~~
Distribution - Substation Service	$0.81~~90~~	$0.81~~90~~

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 41.0
REVISION: 7~~6~~

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130~~10~~.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec-Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
Non-Coincidental Demand	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$ 0.0521~~499~~ per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 41.1
REVISION: 5~~4~~

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.~~0497~~ 0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATON
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 42.0
REVISION: 7~~6~~

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$130~~10~~.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$26.14~~4.85~~ per kW
Winter (Dec – Feb)	@	$19.91~~8.95~~ per kW
Other	@	$13.67~~00~~ per kW
Non-Coincidental Demand	@	$ 5.25~~4.75~~ per kW
Energy Charge	@	$ 0.0521~~499~~ per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period ~~shall be~~ shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.

  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

DAKOTA ELECTRIC ASSOCIATON
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 42.1
REVISION: 5~~4~~

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge
The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.~~0497~~ 0521 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August (prorated based on the number of qualifying calendar days in the billing month). In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2019~~4~~. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase .... $~~85~~95.00
   Three Phase .... $~~100~~110.00

2. Bad Check .... $~~15.00~~11.50

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours .... $~~50~~55.00
      2) Outside normal working hours .... $~~130~~145.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours .... $~~175~~185.00
      2) Outside normal working hours .... $~~315~~340.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck .... $~~280~~340.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours .... $~~70~~80.00
      2) Outside normal working hours .... $~~140~~160.00

6. Pulse Meter (materials and installation) .... $~~500~~750.00

~~7. Temporary Service~~
   ~~a. Non-Winter Months .... $205.00~~
   ~~b. Winter Months (Oct 15 – Apr 15) .... $340.00~~

7~~8~~. Transfer/Connection Charge $17.50

8~~9~~. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way ~~is~~ corridor to be cleared ~~10 feet on each side of the power line~~is 30 feet with no less than10 feet of clearance to any open or bare wire.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a ~~minimum of $500.00 for an extension of 75 feet or less. For extensions longer than 75 feet, the member will be charged~~flat fee of $~~500~~1,000.00 plus $~~8.30~~11.00 per foot ~~for each foot that the~~of line extension~~ exceeds 75 feet~~. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation. In no event will the member be charged more than the actual costs for the extension.
2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.
3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.
4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative's equipment.
5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.
6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.
7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment ~~Complexes~~Facilities, and Seasonal Accounts

1. Dakota Electric Association will provide ~~overhead or underground,~~ single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and ~~apartment complexes~~multi-tenant residential facilities in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the ~~underground~~ primary service to a point of connection designated as either a single-phase or three-phase ~~padmounted~~ transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows for service provided under the applicable rate schedule:

		Sched. 31 Factor	Sched. 41 Factor~~s~~	Sched. 46 Factors	Sched. 70/71 Factors
	Estimated Extension Costs				
-	Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	NA	~~$6.25~~ $10.09	~~$5.54~~ $10.61
-	Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	NA	~~$0.14779~~ $0.15958	~~$0.01959~~ $0.03157	~~$0.01326~~ $.02529
-	Credit per Residential Unit times number of residential units in the complex	$1,282	NA	NA	NA
=	Required Contribution in Aid of Construction				

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

Docket No. E-111/GR-19-478

Exhibit__(DEA-17)
Present Rate Schedules

TABLE OF CONTENTS

CONTACT LIST

DAKOTA ELECTRIC ASSOCIATION

4300 220th Street West

Farmington, MN 55024

(651) 463-6212

GREG MILLER. . . . . PRESIDENT/CEO

MIKE FOSSE . . . . VICE PRESIDENT ENERGY & MEMBER SERVICES

LOU ANN WEFLEN. . . . . VICE PRESIDENT FINANCIAL & INFORMATION SERVICES

RANDY POULSON . . . . VICE PRESIDENT ENGINEERING

DIRK ROTTY. . . . . .VICE PRESIDENT UTILITY SERVICES

DOUG LARSON . . . . VICE PRESIDENT REGULATORY SERVICES

For an emergency, after office hours, call 651-463-6201 or 1-800-430-9722.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: III
SHEET: 1
REVISION:

INDEX OF SERVICE AREAS

INDEX OF SERVICE AREAS

(All areas are in Dakota County unless otherwise indicated.)

Incorporated Areas

- Apple Valley
- Burnside – Goodhue County
- Burnsville
- Cannon Falls
- Coates
- Eagan
- Farmington
- Hastings
- Inver Grove Heights
- Lakeville
- Miesville
- New Trier
- Rosemount
- Vermillion

Unincorporated Areas

- Cannon Falls - Township - Goodhue County
- Castle Rock Township
- Credit River Township - Scott County
- Douglas Township
- Empire Township
- Eureka Township
- Greenvale Township
- Hampton Township
- Marshan Township
- New Market Township - Scott County
- Nininger Township
- Randolph Township
- Ravenna Township
- Sciota Township
- Stanton Township - Rice County
- Vermillion Township
- Waterford Township
- Webster Township - Rice County
- Welch Township - Goodhue County

DEFINITIONS

TERMS AND ABBREVIATIONS

Association	Dakota Electric Association
Billing Period	Time between two successive electric bills -- as near as practicable to 30 days
Commission	Minnesota Public Utilities Commission
Cooperative.	Dakota Electric Association
Member-Owner, Consumer, Consumer/Member . . . . Member-Owner/Consumer, Customer	Any person, firm, or corporation receiving electric service from Dakota Electric Association
Seasonal	Designated consumer/member who receives electric service part-time or only during certain months of the year
Year round	On a regular, daily basis, all months of the year

Other terms used are standard throughout the electric industry.

RATE SCHEDULES

DAKOTA ELECTRIC ASSOCIATION
ELECTRIC RATE BOOK

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 3
Farmington, MN 55024	REVISION: 16

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 3.5
REVISION: 8

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		\$12.00 per month
Energy Charge		\$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	\$14.70 per kW
Other	@	\$11.10 per kW
Plus Applicable Taxes		

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the \$12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by \$0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than \$0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over \$10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or \$1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 4.1
Farmington, MN 55024	REVISION: 1

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE
CONTINUED

Metering

Electric service under this rate must be supplied through a sub-metered circuit (installed at the consumer's expense) and approved electric vehicle charging equipment. Installations must conform to the Association's specifications. The consumer shall supply, at no expense to Dakota Electric, a suitable location for meters and associated equipment used for billing and for load research. For purposes of monitoring consumer load under this pilot program, the Association may install load research metering at its expense.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Data Privacy

Participation in any load research effort as part of this schedule will be strictly voluntary. The Cooperative's use of such load research data will be strictly limited to the provision of electric service. The Cooperative will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the consumer's express, affirmative written informed consent.

Taxes

The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 36
IRRIGATION SERVICE
(Continued)

Interruptible Requirements

Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor applicable to firm irrigation shall be adjusted by $0.0001 per kilowatt-hour, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The energy cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kWh applicable to interruptible irrigation exceeds, or is less than, $0.0497 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

VOLUNTEER FIRE DEPARTMENT RIDER FOR SCHEDULE 41 SMALL GENERAL SERVICE

Availability

Available to a volunteer fire department located in a municipality that does not have a municipal water system and is required to operate a water pump for fire fighting purposes.

Rider

The three consecutive month demand-threshold of 15 kW will be waived for service to qualifying water pumps that meet the above availability clause and all of the following terms and conditions. Qualifying members will be required to pay all applicable monthly fixed charges, energy charges, and taxes according to the terms of Schedule 41.

Terms and Conditions

1. A qualifying volunteer fire department must use a single motor of 50 horsepower or less to operate the single qualifying water pump.
2. Service to any qualifying water pump must be used for the exclusive purpose of responding to fire emergency incidents and training of volunteer firefighters.
3. If the water pump is used for purposes other than responding to fire emergency incidents and training of volunteer firefighters and the monthly demand exceed 15 kW, then the customer will be subject to transfer to the General Service Rate Schedule 46, which includes a demand charge.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$10.10
150 Watt High Pressure Sodium (Closed to new)	$11.99
250 Watt High Pressure Sodium (Closed to new)	$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67

Plus Applicable Taxes

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 11.2
REVISION: 14

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability
Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service
The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service

The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA – OWNED CONTRIBUTION BYMEMBER)
(Continued)

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44 - 4
LED SECURITY LIGHTING
SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.63 per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 12.1
REVISION: Original

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)
(Continued)

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	\$ 10.60	\$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	\$ 11.24	\$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	\$ 8.31	\$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	\$ 10.71	\$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by \$0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than \$0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)
(Continued)

Service Included in Rate

For Standard Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, will make all lamp and glassware renewals, clean the glassware, make all ballast and starter renewals, repair all damaged equipment, and furnish all the materials and labor necessary for these services.

For Basic Service, Dakota Electric will furnish all electric energy necessary to operate the street lighting system, clean the glassware, and repair all damaged equipment. The Member will be responsible for material and labor costs to replace failed components and fixtures not covered by manufacturers warranties. Selection of Basic Service is a “life of fixture” designation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent of $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION　　SECTION: V
4300 220TH Street West　　SHEET: 15
Farmington, MN 55024　　REVISION: 3

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	16.0
Farmington, MN 55024		REVISION::	3

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 46
GENERAL SERVICE
(Continued)

Optional Communication Fee
A monthly Communication Fee of $8.70 will be applied to accounts that participate in riders that require the collection and storage of energy and demand consumption data that is transmitted to the Association by means of digital cellular modem communication.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SEASONAL MEMBER RIDER

Availability

Available to members receiving service under rate schedules 46, 54, 70 or 71 and determined by the Association to be seasonal. Seasonal members qualifying for the Seasonal Member Rider are defined as businesses (service or production) that are closed or shut down for at least three consecutive months during the year. Service is subject to the established rules and regulations of the Association.

Rider

If an account is determined to be seasonal in nature by the Association, the minimum monthly charge shall be the fixed charge for each month of the 12 month period. Minimum monthly demand provisions will not be applied. Members who elect to be disconnected during a portion of the year and then reconnected will be charged a disconnect and a reconnect fee as well as the monthly fixed charge for all 12 months.

SCHEDULE 47
MUNICIPAL CIVIL DEFENSE SIRENS

Availability

This rate will be available to governmental bodies for civil defense siren services where energy consumption is negligible.

Type of Service

Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges

The member shall pay the total estimated installation charges involved to provide service when additional transformers are required. No initial charge will be made to run an overhead service wire from an existing transformer or for making connections to an existing underground feedpoint.

Monthly Rate

$5.00/Month per Installation
Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.0940 per kWh Plus applicable taxes

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Continued)

Conditions of Service
If service is furnished at secondary voltage, the delivery point shall be the metering point unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment on the load side of the delivery point shall be owned and maintained by the member.

If service is furnished at the Cooperative's primary line voltage, the delivery point shall be the point of attachment of the cooperative's primary line to member's transformer structure unless otherwise specified in the contract for service. All wiring, poles, lines and other electric equipment (except metering equipment) on the low side of the delivery point shall be owned and maintained by the member.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity are allocable to sales here under, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability

Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0440 per kWh
Plus Applicable Taxes.		

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand

The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes

The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0550 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, Minnesota 55024

SECTION: V
SHEET: 23.0
REVISION: 10

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
		Plus
Maximum Demand Charge	@	$ 4.75 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE
(Continued)

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15/kW will be applied to the Maximum Billing Demand when the service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

Optional Communication Fee

A monthly Communication Fee of $8.70 will be applied to accounts that participate in riders that require the collection and storage of energy and demand consumption data that is transmitted to the Association by means of digital cellular modem communication.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

DAKOTA ELECTRIC ASSOCIATION		SECTION:	V
4300 220th Street West		SHEET:	25.0
Farmington, Minnesota 55024		REVISION:	Orig

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE
(Continued)

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 60
RIDER FOR STANDBY SERVICE

Application

The Rider for Standby Service is applicable to any member who uses a distributed generation system that serves all or a portion of the member's electric energy requirements and where the member chooses to use the Cooperative's electric system to serve that load when the distributed generation system is either partly or wholly unavailable. When the member uses electric service from the Cooperative, such service will be provided under one of the Cooperative's firm retail electric rate schedules to which this Rider is attached.

The member must enter into a contract with Cooperative for the interconnection and operation of an on-site distributed generation system. The distributed generation system at the member site shall not operate in parallel with the Cooperative's system until the installation has been inspected by an authorized Cooperative representative and final written approval is received from the Cooperative to commence parallel operation.

The minimum term of service taken under this Rider shall be one (1) year or such longer period as may be required under an Electric Service Agreement. Following this initial minimum term, a member receiving standby service may terminate standby service and establish service under a firm service tariff schedule within the same time frame as would be required of a new member with a similar firm service load.

Exceptions to this Application include:

A. Any member taking service under Cooperative's Rider for Parallel Generation as established under Minnesota Rules 7835 shall not be required to take service under this Rider for standby services required to temporarily back up distributed generation systems rated at less than 40 kW;
B. Any member taking service under Cooperative's Rider for Distributed Generation Service shall not be required to pay for service under this Rider for standby services required to temporarily back up distributed generation systems rated at 60 kW or less. For any member with distributed generation systems rated at 60 kW or less, standby service will be available to members through their base rates;
C. Any member, in lieu of service under this Rider, may provide physical assurance to ensure that standby service is not taken. A member requesting physical assurance shall agree to furnish and install an approved load limiting device which shall be set and sealed by Cooperative so that member's use of service will not exceed member's contracted demand. The installed cost of the load limiting device shall be paid by member.
D. Any member using on-site distributed generation to participate in Interruptible Service (Schedules 70 and 71) and generation installed for emergency backup during utility outages.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, Minnesota 55024

SECTION: V
SHEET: 31.2
REVISION: 3

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

If a firm standby member has usage in a billing month, then the demand of such usage will be charged at the demand rate as contained in the base tariff to which this Rider is attached. If the usage demand exceeds the Contracted Standby Demand level, the member's Contracted Standby Demand will be adjusted upward as specified in the Billing Demand clause of this Rider. If the member registers electrical usage that coincides with the Cooperative's wholesale power supplier's applicable billing peak, then additional demand charges may be applied by Cooperative to ensure that the member fully compensates Cooperative for such wholesale power costs.

If there is usage by a non-firm standby member, then the demand of such usage will be charged at no less than the demand rate as contained in the base tariff to which this Rider is attached. (Any higher demand charges for non-firm demand use will reflect higher wholesale demand costs incurred to provide such service.) If the usage demand exceeds the Contracted Standby Demand level, the member's Contracted Standby Demand will be adjusted upward as specified in the Billing Demand clause of this Rider. If the member registers electric use that coincides with the Cooperative's wholesale power supplier's applicable billing peak, then additional demand charges may be applied by Cooperative to ensure that the member fully compensates Cooperative for such wholesale power costs. If additional costs are incurred to provide wholesale power during any time of usage by a non-firm standby member, then the non-firm standby member will be responsible for all such costs.

Energy Charge
Energy consumed by a standby member under this Rider will be charged at the same energy rate contained in the base tariff to which this Rider is attached.

Wheeling Fee
Members requiring delivery of energy over the Cooperative's distribution system to a third party will be charged each month, when such distribution wheeling service is available and provided, at a rate equal to the applicable distribution standby reservation fee specified in this rider. If firm wheeling service is required, then arrangements will be made to ensure that distribution system facilities are adequate to provide such firm wheeling service. The cost of any required system modifications will be the responsibility of the entity requesting the firm wheeling service.

Rate Adjustments
Bills shall be subject to all adjustments applicable to consumption under the base schedule to which this Rider is attached.

Billing Demand
The member shall contract for a specific kilowatt demand of standby service with the maximum being the amount of load served by the member's distributed generation system. In the event the Contracted Standby Demand is exceeded in any month, such higher demand shall be considered the new Contracted Standby Demand. Such adjustment of the Contracted Standby Demand applicable to Reservation Fees will recognize circumstances where on-going utility firm service is being provided in addition to standby service.

The billing demand for applying Distribution Reservation Fees for standby service to on-site distributed generation will be determined by subtracting the billing demand for usage supplied by the Cooperative during the same time period as the highest total member electrical demand in the billing month (supplied by the Cooperative and the member's distributed generation system). The billing demand for applying Distribution Reservation Fees for standby service to wholesale generation will be determined by subtracting the billing demand for usage supplied by the Cooperative from the Contracted Standby Demand. The billing demand for applying Generation and Transmission Reservation Fees will be determined according to the terms and conditions of the Cooperative's wholesale power supplier.

The billing demand(s) for usage will be determined and applied as specified in the base tariff to which this rider is attached.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Stranded Investment

Any member who installs load limiting equipment to ensure that standby service is not taken (physical assurance) and does not intend to deliver power into the distribution system will have the option of making a lump sum payment to Cooperative for stranded distribution investment. Dakota Electric shall provide support for the one-time charge to recover stranded distribution investments to physical assurance members before it begins collecting the charge. If such lump sum payment is not made, then the member will be subject to distribution standby charges based on the member's typical demands incurred prior to requesting physical assurance status.

Billing and Terms of Payment

Billing and terms of payment shall be governed as set forth in the Cooperative's applicable base rate schedule.

Terms and Conditions of Service

1. The member shall execute an Electric Service Agreement with the Cooperative which shall specify:
    a. Standard rate schedule (to which this Rider is attached);
    b. Contracted Standby Demand;
    c. Generator Nameplate Rating; and
    d. Type of Standby Service (firm or non-firm).
2. Service hereunder is subject to Cooperative's *Interconnection Process for Distributed Generation Systems* and *Distributed Generation Interconnection Requirements* as may be modified from time-to-time. Current documents are available on DEA's Web site at dakotaelectric.com.
3. Cooperative will install all metering equipment necessary to monitor services provided to ensure adequate measurements are obtained to support necessary application of charges. The member will be charged an up-front lump sum for the installed cost of such metering equipment.
4. The member shall make provision for on-site metering. All energy received from and delivered to the Cooperative shall be separately metered. The Cooperative may require metering of the generation output.
5. The member shall pay for all interconnection costs incurred by the Cooperative made necessary by the installation of the distributed generation system.
6. The Cooperative reserves the right to disconnect the member's generator from the distribution system if it interferes with the operation of the Cooperative's equipment or with the equipment of other Cooperative members.
7. The Cooperative shall not be obligated to supply standby service for a member's load in excess of the capacity for which the member has contracted.
8. The member shall be liable for all damages or costs caused by member's use of power in excess of contracted for capacity.
9. Cooperative may require the member to furnish and install an approved load limiting device which shall be set and sealed by Cooperative so that the member's use of service will not exceed the number of kilowatts contracted for by member.
10. The member shall furnish updated documentation to the Cooperative if there are changes to the maximum capacity and reliability of the power source for which the member requires Standby Service.
11. Cooperative and the member will coordinate the planning and determining of a schedule for performance of periodic maintenance of the member's facilities, such maintenance shall be scheduled to avoid wholesale power billing peaks or as agreed upon in the contract. Cooperative will require the member to provide reasonable notice of its proposed schedule for maintenance. The duration of the agreed maintenance schedule may thereafter be extended only with the consent of the Cooperative in response to the member's request received prior to the end of the maintenance period.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

12. The Cooperative reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Electric Service Agreement.
13. Cooperative may be reimbursed by the member for costs which are incurred, or which have been previously incurred, in providing facilities which are used principally or exclusively in supplying service for any portion of the member's requirements which are to be normally supplied from a source of power other than the Cooperative's electric system.
14. All electricity delivered shall be for the exclusive use of the member and shall not be resold.
15. Member shall indemnify Cooperative against all liability which may result from any and all claims for damages to property and injury or death to persons which may arise out of or be caused by the erection, maintenance, presence, or operation of the co-generation facility or by any related act or omission of the member, its employees, agents, contractors or subcontractors.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION

Application
The Rider for Distributed Generation is applicable as follows to any member taking service under one of the Cooperative's standard electric rate schedules and who has entered into an Electric Service Agreement with Cooperative for the interconnection and operation of an on-site extended parallel distributed generation system:

1. The distributed generation system must be an operable, permanently installed or mobile generation facility connected in parallel to the utility distribution system serving the member receiving retail electric service at the same site.
2. The distributed generation system must be fueled by either natural gas, a renewable fuel, or another similarly clean fuel or combination of fuels.
3. The distributed generation system can not have more than 10 MW of interconnected capacity at a point of common coupling to Cooperative's distribution system.
4. The interconnection and operation of the distributed generation system at each point of common coupling shall be considered as a separate application of the Rider.
5. All provisions of the applicable standard service schedule shall apply to distributed generation service under this Rider except as noted below.

In lieu of service under this Rider, the member and Cooperative may pursue reasonable transactions outside the Rider; or member may take service, as applicable, under Cooperative's Rider for Parallel Generation as established under Minnesota Rules 7835 – Cogeneration and Small Power Production.

Definitions
Member is an entity receiving retail electric service from Cooperative at the same site as the distributed generation system.

Extended Parallel means the distributed generation system is designed to remain connected with the Cooperative's distribution system for an extended period of time.

Scheduled Maintenance service is energy, or energy and capacity, supplied by the Cooperative during scheduled maintenance of the member's non-utility source of electric energy supply (distributed generation system).

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Supplemental service is electric energy, or energy and capacity, supplied by the Cooperative to the member when the member's non-utility source of electricity (distributed generation system) is insufficient to meet the member's own load. Supplemental Service can take two forms: residual retail service and load-following service. **Residual Retail Service** is intended for a Dakota Electric member who has an alternate source of electric energy supply which normally supplies only a portion of the member's electrical load requirements and who requires firm service for the remaining portion of the member's electrical requirements. Such Residual Retail Service is available under the Cooperative's firm retail electric rate schedule to which this rider is attached. **Load Following Service** is intended for a Dakota Electric retail member who has an alternate source of electric energy supply which has an output that is variable and dependent on the thermal load characteristics of the retail member and therefore, serves all or a portion of the member's electrical load requirements for a portion of the time and requires use of utility service for supply of energy at all other times. This load following service will be evaluated and contracted for on an individual basis with a member based on the specific variable load requirements of the member. Since a member may have control over the thermal load characteristics that affect the output of distributed generation facilities in this situation, we believe the best way of providing service is on an individual contracted basis. This will recognize that some members may rely on utility service during high cost on-peak periods while other members may require such utility service only during lower cost off-peak periods.

Unscheduled Outage service is energy, or energy and capacity, supplied by the Cooperative during unscheduled outages of the member's non-utility source of electric energy supply (distributed generation system).

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Services
Services provided under this Rider may include services from the Cooperative to member and from member to Cooperative. The following rates, charges, credits and payments are applicable for such services in addition to all applicable charges for service being taken under Cooperative's standard rate schedule:

Services from Cooperative to Member
A monthly service charge to recover incremental metering, operation, and maintenance costs may be applied upon Commission approval.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Services from Cooperative to Member

Interconnection Services
Interconnection services include services such as engineering/design studies, Cooperative system upgrades and testing as further described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems*. Charges for such interconnection services shall be as described in the Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Supply Services
Supply services include standby services such as scheduled maintenance and unscheduled outages as provided under Cooperative's *Rider for Standby Service*. Supplemental service is available under the Cooperative's firm retail electric rate schedule to which this Rider is attached.

Transmission Services
Transmission services include reservation and delivery of capacity and energy on either a firm or non-firm basis and those ancillary services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation over Transmission Providers' Transmission System. These ancillary services include services such as Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control from Generation Sources, Regulation and Frequency Response, Generator Imbalance, Operating Reserve – Spinning Reserve and Operating Reserve – Supplemental Reserve. Transmission Services are provided as applicable under Cooperative's wholesale power supplier's approved Open Access Transmission Tariff (OATT).

Distribution Services
Distribution services include reservation and delivery of capacity and energy and those indirect services that are necessary to support the delivery of capacity and energy over Cooperative's distribution system. These indirect services include allocated support services or expenses such as operation and maintenance, member accounts, member service and information, administrative and general, depreciation, interest and taxes. Members requiring contracted distribution standby service of more than 60 kW and/or delivery of energy and capacity over Cooperative's distribution system to a third party will be charged for such distribution services at a rate equal to the distribution charge specified in the Cooperative's *Rider for Standby and Supplemental Service*.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Services from Member to Cooperative

Capacity/Energy
Member may sell all of the energy produced by the distributed generation system to the Cooperative, use all the distributed generation energy to meet its own electrical requirements, or use a portion of the energy from the distributed generation system to meet its own electrical needs and sell the remaining energy to the Cooperative.

If the member offers to sell energy to the Cooperative, then such energy and capacity shall be purchased by the Cooperative's wholesale power supplier under the rates, terms and conditions for such purchases as established by the wholesale power supplier. Great River Energy Rate Rider T is available on GRE's Web site; greatriverenergy.com, and on DEA's Web site; dakotaelectric.com.

Distribution Credits
A distribution credit may be given if the distributed generation system allows the Cooperative to defer or avoid distribution system upgrades. Distribution credits to the member should equal the Cooperative's avoided distribution costs resulting from the installation and operation of the distributed generation system. The Cooperative shall provide, upon member's written request, areas of the distribution system that could be likely candidates for distribution credits as determined through the Cooperative's normal planning process. The Cooperative shall also provide to the member the minimum size distributed generation system required in each of the areas to qualify for the distribution credit along with general operational requirements necessary for the distributed generation system to meet, so as to be able to receive distribution credits.

Upon receiving an interconnection application from the member for a distributed generation interconnection, along with a written request for distribution credits, the Cooperative will complete an initial screening study to determine if the project has the potential to receive distribution credits. The member shall be responsible for the cost of the screening study. If the Cooperative's study shows that there exists potential for distribution credit, the Cooperative shall, at its own expense, pursue further study to determine the distribution credit, as part of its annual distribution planning study. If distribution credits are identified, then such credits will be paid in conjunction with an agreement with the member to supply distribution support utilizing the member's generation system.

Line Loss Credits
If the member requests the Cooperative to provide a specific line loss study, at the member's expense regardless of the study's outcome, the member may be eligible for additional line loss credits if the study supports such credits.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

Renewable Credits

If the member installs a renewable distributed generation system and the Cooperative's wholesale power supplier's purchase of energy and capacity from such facility allows the wholesale power supplier to avoid the need to purchase renewable energy elsewhere, then the purchase of such renewable energy and capacity will equal the avoided cost of renewable purchases as provided under the wholesale power supplier's applicable rates, terms and conditions for such purchases In the event that the member producing the power receives renewable energy credits – that is, the member is paid by the purchasing company the avoided cost of renewable energy purchases – then this transaction will constitute a transfer from the member to the purchasing company of the property rights for those renewable attributes specific to the renewable energy generated by the member and for which the purchasing company paid renewable energy credits. The member may receive renewable credits or tradable emission credits but not both.

Tradable Emissions Credits

If the purchase of energy and capacity by the Cooperative's wholesale power supplier under the "must buy" provision described above results in the wholesale power supplier receiving an economic value associated with tradable emissions, then tradable emissions credits will be provided to the member under terms established by the wholesale power supplier that equal the credit revenues associated with the DG facilities of such emission credits received by the wholesale power supplier. The member may receive either renewable credits or tradable emissions credits but not both.

Terms and Conditions of Service

The following terms and conditions apply to this Rider:

1. Service hereunder is subject to Cooperative's *Interconnection Process for Distributed Generation Systems* and *Distributed Generation Interconnection Requirements* as may be modified from time-to-time. Current documents are available on DEA's Web site: dakotaelectric.com.

2. Cooperative will install all metering equipment necessary to monitor services provided to ensure adequate measurements are obtained to support necessary application of rates, charges, credits and payments. The member will be charged an up-front lump sum for the installed cost of such metering equipment.

3. The member will be compensated monthly for all energy delivered to Cooperative's wholesale power supplier. The timing for these payments is subject to annual review.

4. The member shall make provision for on-site metering. All energy received from and delivered to the Cooperative shall be separately metered. The Cooperative may require metering of the generation output.

SCHEDULE 61
RIDER FOR DISTRIBUTED GENERATION
CONTINUED

5. The member shall pay for all interconnection costs incurred by the Cooperative made necessary by the installation of the distributed generation system.

6. Power and energy purchased by the member from the Cooperative shall be under the applicable retail rates for the purchase of electricity.

7. The Cooperative reserves the right to disconnect the member's generator from its system if it interferes with the operation of the Cooperative's equipment or with the equipment of other Cooperative members.

8. The member shall execute an Electric Service Agreement with the Cooperative which may include, among other provisions, a minimum term of service.

Billing and Terms of Payment

Billing and terms of payment shall be governed as set forth in the Cooperative's applicable base rate schedule.

To the extent that Cooperative receives service from a member under this Rider, payment for such services shall be netted against any charges for Cooperative-supplied services hereunder.

DAKOTA ELECTRIC ASSOCIATION	SECTION: V
4300 220th Street West	SHEET: 41.0
Farmington, MN 55024	REVISION: 6

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability
Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period
The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand
The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand
The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control
The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance
Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)
(Continued)

Minimum Billing Demand

The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment

The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service

A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0497 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Control Period

The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)
(Continued)

Excess Demand Charge
The Excess Demand Charge will be applied to the Coincidental Demand that exceeds the Predetermined Demand Level (PDL) for a member using the partial interruptible control option when the member does not reduce demand to the PDL during a control period. The Excess Demand Charge is applied per month.

Minimum Billing Demand
The Minimum Billing Demand for any billing period shall be no less than 50 percent of the highest non-coincidental demand during the preceding 11 months.

Power Factor Adjustment
The member agrees to maintain as near unity power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent; the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Primary Voltage Service
A discount of $0.15 per kW of billing demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15 per kW discount.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in wholesale power costs, Dakota Electric's conservation tracker account balance, and real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour applicable to this service exceeds, or is less than $0.0497 per kilowatt-hour sold as described in the Energy Cost Adjustment Rider (ECA) (Sheet 52). The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 90
OPTIONAL RENEWABLE ENERGY RIDER
(**Wellspring Wind and Wellspring Solar**)

Availability
Available to any member taking service concurrently under another rate schedule. This rate is for the purchase of energy from wind and solar renewable sources. Members requesting service under this optional rider must remain on the rider for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Subscription Requirement
Members desiring to participate in the Optional Renewable Energy Rider will specify the type of resource and either a fixed or a variable monthly amount of renewable energy (in one or more 100 kWh blocks) that they will purchase. The fixed monthly subscription level may not exceed a member's lowest actual or estimated monthly consumption level. Under the variable monthly subscription, the member will automatically purchase the maximum number of 100 kWh blocks or renewable energy each month that does not exceed the member's actual consumption level for that month.

Monthly Rate

Wind Renewable Energy (per 100 kWh)	$0.20
Solar Renewable Energy (per 100 kWh)	$2.00
Plus Applicable Taxes	

The monthly renewable energy rate will consist of the wholesale power cost for this service plus any over- or under-recovery balance from the prior year. This monthly renewable energy rate will be shown as a separate line item on a member's bill. This charge per 100 kWh is in addition to the applicable rate schedule currently serving the member.

Rate Adjustments
The monthly rate will be adjusted under the following two circumstances. First, the rate will change to reflect changes in wholesale power costs associated with this service. Dakota Electric will file such wholesale rate adjustment calculations with the Minnesota Public Utilities Commission prior to implementing the rate revision. Second, the monthly rate will include any over- or under-recovery of renewable energy costs approved for recovery under this rider. In early January each year, Dakota Electric will submit a filing to the PUC documenting any change in wholesale power costs and any over- or under-recovery of renewable energy costs for the prior calendar year.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 90
OPTIONAL RENEWABLE ENERGY RIDER
(**Wellspring C&I**)

Availability

Wellspring C&I is available to commercial and industrial member-consumers receiving service under Schedules 46, 54, 70, or 71. Participating members may purchase the retirement of any quantity of Renewable Energy Certificates (RECs) by Dakota Electric's wholesale power supplier, specified in kWh, in relation to either a designated annual percentage of load (%), or monthly energy amount (kWh) up to their total annual energy usage supplied by Dakota Electric. Service is subject to the established rules and regulations of the Association.

Subscription Requirements

A retail agreement between Dakota Electric and the member-consumer is required that reflects a five (5) to ten (10) year commitment and conforms to specifications set forth in the annual program guide of Dakota Electric's wholesale power supplier. C&I member-consumer purchases must meet one of the following minimum thresholds:

a) 1,500,000 kWh annually per participant; or
b) corporate aggregation level at 5,000,000 kWh annually.

Any retail sale to an individual member-consumer or multi-site entity that is expected to exceed 10,000,000 kWh annually, anytime during the term, requires Dakota Electric to receive prior approval from our wholesale power supplier.

To be eligible for Wellspring C&I, retail and wholesale agreements must:

a) be executed prior to September 1st,
b) be for full calendar year terms,
c) commence on either the preceding, or next occurring, January 1st, and
d) have a copy provided to the wholesale power supplier within fifteen (15) days of execution.

Monthly Rate

Wellspring C&I will be billed as a specified rate per kWh for the entire five (5) to ten (10) year term of the agreement between Dakota Electric and the individual member-consumer. The rate per kWh for Wellspring C&I reflects a pass-through of charges from the wholesale power supplier. The rate for each agreement is established at the time the agreement is signed. This monthly renewable energy rate will be shown as a separate line item on a member's bill. This charge is in addition to the applicable charges for the rate schedule currently serving the member.

Termination Penalties

Early termination penalties will apply to agreements that are terminated early for convenience or otherwise voluntary reasons. Early termination penalty shall equal the last 12 months purchase amount multiplied times the purchase rate as specified in the agreement. Early termination penalties may be waived for agreements that are terminated early for involuntary reasons such as facility closings, ownership change, bankruptcy, etc.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SPECIAL FEES OR CHARGES

1. Meter Test at Member's Request
   Single Phase $85.00
   Three Phase $100.00

2. Bad Check $15.00

3. Reconnection Charge (after disconnect, same consumer)
   a. Self-contained Metering (one person, one vehicle)
      1) Working hours $50.00
      2) Outside normal working hours $130.00

   b. Current Transformer-rated Metering (two-person crew, one truck)
      1) Working hours $175.00
      2) Outside normal working hours $315.00

4. Service Charge
   (outside normal working hours when problem is not with Association's equipment)
   Two-person crew, one truck $280.00

5. Load Management Service Charge
   (when problem is not with Association's equipment)
      1) Working hours $70.00
      2) Outside normal working hours $140.00

6. Pulse Meter (materials and installation) $500.00

7. Temporary Service
   a. Non-Winter Months $205.00
   b. Winter Months (Oct 15 – Apr 15) $340.00

8. Transfer/Connection Charge $17.50

9. Member Contracted Hourly Work
   Dakota Electric is periodically asked to perform on-site service work. Such services will be provided at a pre-arranged hourly rate.

RESOURCE ADJUSTMENT RIDER

Application

Applicable to all bills for retail electric service that include a purchased power cost adjustment clause.

Resource Adjustment (RA)

Monthly member energy charges shall be adjusted for changes in purchased power costs and changes in Dakota Electric's Tracker Account balance. These two changes shall be reflected on member bills through a Resource Adjustment. The applicable RA factor shall be determined annually as described below.

Determination of the Resource Adjustment Factor

The Resource Adjustment factor shall be determined by adding the annualized power cost adjustment factor to the most recent year-ending Tracker Account factor. The Tracker Account factor shall be the quotient of the recoverable Tracker balance, divided by projected retail energy sales that are applied in the power cost adjustment factor

The year used for the annualized Resource Adjustment will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RA shall be filed with the Public Utilities Commission each year before implementation.

All costs appropriately charged to Dakota Electric's Tracker Account shall be eligible for recovery through this adjustment. Revenues received from the application of the RA shall be applied toward power costs and the Tracker Account in a manner consistent with the determination of the RA factor.

ENERGY COST ADJUSTMENT RIDER

Application

Applicable to service provided under Interruptible Service Schedule 70, Schedule 71 and Interruptible Irrigation (Schedule 36).

Determination

The Energy Cost Adjustment (ECA) will increase/decrease by $0.0001 per kilowatt-hour for every corresponding $0.0001 increase/decrease in Dakota Electric's projected wholesale cost per kilowatt-hour sold applicable to Schedule 70, Schedule 71, and Interruptible Irrigation. Total projected energy costs for this service will include all energy costs for energy supply excluding costs for load management programs and including applicable wholesale energy cost adjustments. This adjustment will be calculated annually and applied monthly on member bills.

PROPERTY TAX ADJUSTMENT RIDER

Application
Applicable to all bills for retail electric service under Dakota Electric's retail rate schedules.

Rider
There shall be included on each member's bill a Property Tax Adjustment which shall be the applicable Property Tax Adjustment factor multiplied by the member's energy usage before any applicable city surcharge or sales tax. The Property Tax Adjustment factor shall be reflected on member bills through a "Resource and Tax Adjustment" line item on member bills. The applicable Property Tax Adjustment factor shall be determined annually as described below.

Determination of the Property Tax Adjustment Factor
The Property Tax Adjustment factor shall be determined by first allocating the incremental annual property tax expense to each class according to each class' relative responsibility for property taxes as determined in the most recent general rate case class cost of service study. Each class allocation will then be divided by projected retail energy sales applicable to each class to determine the property tax adjustment factor for each class.

Calendar-year property tax adjustment factors will be recovered during the period from January 1 through December 31. The property tax adjustment factor shall be filed with the Public Utilities Commission each year before implementation.

Recoverable Property Tax Expenses
Recoverable Property Tax expenses shall be the incremental property tax expense not recovered through base rates as estimated for the designated projected twelve month recovery period, plus unrecovered or less over-recovered Recoverable Property Tax expenses for a prior designated twelve month recovery period.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: V
SHEET: 54.0
REVISION: 10

FRANCHISE FEE SURCHARGE RIDER

Application

A surcharge will be included in the monthly bills computed under the indicated rate schedules effective in the following Minnesota Communities.

The Cooperative remits 100% of the franchise fees collected to the local government.

Rate Schedules		Apple Valley [a] (2.0%)	Burnsville [b]	Inver Grove Heights [c]
Residential and Farm Service	(Schedule 31)	X	$1.00	$2.75
Residential and Farm Demand Control Rate	(Schedule 32)	X	$1.00	$2.75
Residential Electric Vehicle Service	(Schedule 33)	X	NA	NA
Irrigation Service	(Schedule 36)	X	$3.00	$3.00
Small General Service	(Schedule 41)	X	$3.00	$3.00
Security Lighting Service	(Schedule 44)	X	NA	NA
Street Lighting Service	(Schedule 44-1)	X	NA	NA
Street Lighting Service	(Schedule 44-2)	X	NA	NA
Custom Residential Street Lighting	(Schedule 44-3)	X	NA	NA
Low Wattage Unmetered Service	(Schedule 45)	X	NA	NA
General Service <75 kW	(Schedule 46)	X	$10.00	$25.00
General Service ≥75 kW	(Schedule 46)	X	$45.00	$25.00
Municipal Civil Defense Sirens	(Schedule 47)	X	NA	NA
Geothermal Heat Pump	(Schedule 49)	X	NA	NA
Controlled Energy Storage	(Schedule 51)	X	NA	NA
Controlled Interruptible Service	(Schedule 52)	X	NA	NA
Residential and Farm Time-of-Day Service	(Schedule 53)	X	$1.00	$2.75
General Service Optional TOD <75 kW	(Schedule 54)	X	$10.00	$25.00
General Service Optional TOD ≥75 kW	(Schedule 54)	X	$45.00	$25.00
Residential and Farm Time-of-Day Service	(Schedule 56)	X	$1.00	$2.75
Standby Service Rider	(Schedule 60)	X	NA	NA
Distributed Generation Rider	(Schedule 61)	X	NA	NA
Interruptible Service (Full Interruptible)	(Schedule 70)	X	$45.00	$25.00
Interruptible Service (Partial Interruptible)	(Schedule 71)	X	$45.00	$25.00
Cycled Air Conditioning Service	(Schedule 80)	X	NA	NA
Renewable Energy Rider	(Schedule 90)	X	NA	NA

a. The maximum fee that will be applied to any account will not exceed $25.00 per month.
b. Effective July 2016.
c. Effective with the January 2018 billing month.

FRANCHISE FEE SURCHARGE RIDER (Continued)

Notification

The Cooperative will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Cooperative receives less than 60 days' notice of a repealed or reduced fee from a city, the Cooperative will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

When a new franchise fee is implemented, the Cooperative will notify affected consumers through a joint letter mailed on behalf of the Cooperative and local government entity imposing the franchise fee. Such joint letters will be submitted to the Commission along with other relevant documentation referenced above and will at least include the following statement:

> The Cooperative provides electric service within the City limits under the terms of a Franchise Agreement with MUNICIPALITY. An electric Franchise Fee of X% OF GROSS REVENUES/$X PER METER/$ PER KWH will be imposed on consumers effective MM/DD/YYYY. The line item will appear on your bill as "City Fee." The Cooperative remits 100% of this fee to the MUNICIPALITY."

The franchise fee will be labeled as "City Fee" on monthly bills.

COMPETITIVE SERVICE RIDER

Availability

Available at Association's discretion to Commercial and Industrial members that have electric service requirements which are subject to effective competition. Effective competition exists if a member is located in Association's service territory and has the ability to obtain its energy requirements from an energy supplier not rate-regulated by the Minnesota Public Utilities Commission.

Rate

Standard service rate provisions apply except the level of the demand and/or energy charges may be decreased for each member based on a consideration of member's load characteristics and lowest cost competitive energy supply.

Terms and Conditions of Service

1. Members must provide Association with information which documents that member is not likely to take service provided by any other electric tariff available from Association.
2. Minimum load served under this Rider is 500 kW.
3. Member must execute an electric service agreement with Association which will include:
   a. The minimum rate under this Rider, which will recover at least the incremental cost of providing service, including the cost of incremental capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.
   b. The maximum rate reduction possible under this Rider, which will not exceed the difference between the standard tariff and the cost to the member of the lowest cost competitive energy supply.
   c. The term of service under this Rider, which must be no less than one year and no longer than five years.
   d. The size of the load served under this Rider
   e. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for member, an explanation of why an electric energy review was not necessary will be included.

COMPETITIVE SERVICE RIDER
(Continued)

4. The Association within a general rate case is allowed to seek recovery of the difference between the standard tariff and this Rider times the usage level during the test year period.
5. A rate under this Rider shall meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other members in this same member class.
6. Unless the Commission determines that it would be in the public interest, a rate under this Rider shall not compete with district heating and cooling provided by a district utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, paragraph (c).
7. A rate offered under this Rider may not be offered to a member in which the Association has a financial interest greater than 50 percent.

Regulatory Review

This rate offered under this Rider will be effective on an interim basis after filing by Association of the proposed rate with the Commission and upon the date specified in the electric service agreement. If the Commission does not approve the rate, Association may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the member who was offered the competitive rate.

The Commission has the authority to approve, modify or reject a rate under this Rider. If the Commission approves the competitive rate, it becomes effective as agreed to by the Association and member. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Association and the member. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Association on its behalf or on the behalf of the member, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

MEMBER ENERGY EXCHANGE RIDER

Availability

The Member Energy Exchange Program is available to any general service member with 100 kW minimum demand reduction capability taking service concurrently under either rate schedule 46, 70 or 71. This rider provides Dakota Electric and its power supplier(s) with the opportunity to pay members for reducing their energy needs during certain peak periods. Member participation during each individual exchange period is strictly voluntary. Members may elect to participate in an individual exchange period or decline without explanation. This rider is available at the Cooperative's discretion.

Participation Requirements

The following participation requirements apply:

1. Member must provide a minimum electrical demand reduction of 100 kW;
2. Member loads covered by a load management program or rate are not eligible;
3. Member must reduce energy requirements for a minimum of two hours; and
4. Member may be required to reduce energy requirements for a maximum of six hours in any 24-hour period.

Notification and Pricing

Two options are available for customers participating in the Member Energy Exchange Program

Option A – This option is for a member requiring a 24-hour advance notice. Option A notification and pricing is as follows:

1. Member receives a day-ahead posted price;
2. Member indicates intended action plans for the next day;
3. Member receives a two-hour notification prior to the beginning of the energy reduction period;
4. Member curtails energy usage; and
5. Member receives a separate payment or a credit on the electric bill.

MEMBER ENERGY EXCHANGE RIDER
(Continued)

Notification and Pricing (continued)

Option B – This option is for a member that can respond to a maximum two-hour notice. Option B notification and pricing is as follows:

1. Member receives a two-hour notification that includes the posted price prior to the beginning of the energy reduction period (Option B will be valued higher than Option A);
2. Member curtails energy usage; and
3. Member receives a separate payment or a credit on the electric bill.

Validation

The following metering and validation provisions will apply for participation in this program:

1. Member must have electronic 15-minute interval metering, interrogation software and telephone line;
2. An assessment of the verifiable energy reduction capability will be performed before a member may participate; and
3. The member's ability to reduce demand to the agreed-upon level will be tested and verified.

VOLUNTARY ENERGY REDUCTION RIDER

Availability

The Voluntary Energy Reduction Rider is available to any General Service member that is demand metered. This rider provides Dakota Electric and its power supplier(s) with the opportunity to pay members for reducing their energy needs during certain peak periods. Member participation is strictly voluntary. This rider is available at the Cooperative's discretion.

Participation Requirements

The following participation requirements apply:

1. Member must be demand metered by Dakota Electric;
2. Member loads covered by a load management program or rate are not eligible; and
3. Member must reduce energy requirements for a minimum of two hours.

Notification and Pricing

Dakota Electric will contact members and determine their interest in participating in the Voluntary Energy Reduction Program. The offer to participate in this rider will include:

1. An estimate of the member's demand reduction based on historical patterns;
2. Indication of duration of voluntary reduction;
3. Identification of beginning hour and ending hour of voluntary reduction; and
4. Offer price per kWh.

Participating members will curtail specified energy usage during identified voluntary reduction periods. Members will then receive compensation through a separate payment or a credit on the electric bill.

MEMBER SPECIFIC DISCOUNT RIDER

Availability

Available to Commercial and Industrial members receiving service under Schedules 46 and 54 that have electric load that qualifies for a targeted wholesale capacity rate discount from the Association's wholesale power supplier. Service will be provided under the terms of a member-specific contract.

Rate

Standard rate provisions for Schedules 46 and 54 apply, except that a discount will be applied to the monthly bill based on the member's demand during the wholesale coincident billing peak and the qualifying discount level. The monthly billing discount is available for up to five (5) consecutive years measured from the date electric service is first provided to the qualifying new retail load, or under other terms as offered by the Association's wholesale power supplier.

A monthly Communication Fee of $8.70 per meter will be charged for digital cellular modem communication.

Terms and Conditions of Service

1. Available to new retail load with monthly coincident billing peak demand greater than or equal to 750 kW.
2. Monthly non-coincident load factor must be greater than or equal to 40%.
3. Dakota Electric must supply all (100%) of the retail load's electric requirements. On-site generation is not allowed.
4. Load will be ineligible for Interruptible Commercial and Industrial Service (Schedules 70 and 71) during the term of the agreement and, upon expiration, for an additional three years.
5. Each month that the metered coincident billing peak demand of the qualifying load is greater than or equal to 750 kW, a discount will be applied to the demand of the qualifying load as specified by Dakota Electric's wholesale power supplier.
6. No discount will be applied to the demand of the member's load in a month where the metered coincident billing peak demand of the load is less than 750 kW.
7. A Member Specific Rate may not be offered to a member in whom the Association has a financial interest greater than 50 percent.
8. Member must provide Association with information which documents that the member electrical load from the Association will qualify for the targeted wholesale capacity rate discount from Dakota Electric's power supplier.

MEMBER SPECIFIC DISCOUNT RIDER
(Continued)

9. Member must execute an electric service agreement with Association which will at least include:
    a. The billing rate components, specified as credits or charges as applicable.
    b. The term in years for firm service.
    c. The size of the load served under this Rider.
    d. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for member, an explanation of why an electric energy review was not necessary will be included.
10. The Association will track the wholesale power cost credits associated with each Member Specific Discount and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.

Regulatory Review
Each Member Specific Discount will be filed with the Public Utilities Commission (as a confidential information filing) before implementation. These confidential information filings will provide an overview of the discount being provided and confirm that the discount is a pass-through from Dakota Electric's wholesale power supplier.

LARGE LOAD HIGH LOAD FACTOR RIDER

Availability
Available to Commercial and Industrial members receiving service under Schedules 46 and 54 that have electric load at an individual site that meets the qualifying demand and load factor thresholds of the Association's wholesale power supplier.

Rate
Standard service rate provisions for Schedules 46 and 54 apply, except that a discount will be applied to the member's monthly bill based on the member's calculated load factor. Qualifying loads may move between load factor tiers monthly based on a changing ANCLF (or PNCLF). Credits will be issued monthly for the following load factor tiers:

Tier	ANCLF / PNCLF
1	62.00 % to 74.99%
2	75.00% to 89.99%
3	90.00 % to 100.00 %

A monthly Communication Fee of $8.70 per meter will be charged for digital cellular modem communication.

Terms and Conditions of Service
1. Dakota Electric must supply all (100%) of the member's electric requirements. On-site generation is not allowed.
2. The member will not receive a credit under both the LLHLF rate and any other load management program.
3. The member's qualifying load at an individual site must achieve a Non-Coincident Peak Demand (NCPD) of at least 1,000 kW in any period of sixty (60) consecutive minutes at least one time in the preceding 12-month period.
    a. NCPD shall be the highest actual metered demand and not an estimated, average or calculated value.
4. The member's qualifying load at an individual site must have an Annual Non-Coincident Load Factor (ANCLF) in the preceding 12-month period that is greater than or equal to 62%.
    a. All Load Factor calculations will be based only on the individual member's actual demand and energy recorded during the preceding twelve (12) months at an individual site.
    b. No adjustments will be made for any load management programs, abnormal weather, member load anomaly, or member growth (expected or actual).

LARGE LOAD HIGH LOAD FACTOR RIDER
(Continued)

5. New metered loads with less than twelve (12) months of actual load data may substitute a Partial-Year Non-Coincident Load Factor (PNCLF) for the ANCLF qualification requirement, only during the first eleven (11) months of electric service.
   a. If a member has a significant expansion of load at the site and the member's NCPD increases by more than 50% over the previous year's average monthly Peak Demand, then the member shall have the ability to use the PNCLF as the basis for the credit that applies to the entire member load.
   b. Once a member "resets" the load factor calculation and begins using the PNCLF, the member may not revert to the historical ANCLF for the next 11 months.
   c. Transfer of ownership alone does not qualify load to be considered "new".
6. No loads will qualify for the LLHLF credit retroactively. Monthly calculations will be made for qualification in the previous month.
7. Dakota Electric will automatically adjust the LLHLF credit provided to members to pass through any future changes made by its wholesale power supplier.
8. The Association will track the wholesale power costs associated with all Large Load High Load Factor credits and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.

SCHEDULE 72
CONTRACT RATE SERVICE

Availability

Available at Association's discretion, within its assigned service territory, to large Commercial and Industrial members that are subject to effective competition and have electric service requirements as described in the Terms and Conditions of Service clause. Effective competition exists if the member has the ability to obtain its energy requirements from an energy supplier not rate-regulated by the Minnesota Public Utilities Commission (Commission). Service will be provided under the terms of a member-specific electric service agreement.

Rate

Applicable charges will be detailed in an electric service agreement.

Terms and Conditions of Service

1. Individual contract rates will only be offered in coordination with Dakota Electric’s wholesale power supplier.
2. Minimum load served under this Contract Service is 10 MW.
3. Distribution and/or transmission facilities to serve the Contract Service load will be provided as specified in the electric service agreement with the member. A contribution in aid of construction (CIAC) will be required if the estimated investment in distribution and/or transmission facilities is not justified by the anticipated revenue.
4. Member must execute an electric service agreement with Association which will at a minimum include:
   a. Location of the consumer site within the Cooperative’s service territory.
   b. Affirmation that 1) the consumer is able to locate the load/facility at another site and obtain energy requirements from an energy supplier that is not regulated by the Commission and 2) that the consumer is not likely to take service from the Cooperative if the consumer was charged the Cooperative’s standard tariffed rate.
   c. Identification of billing components and rates to be applied to each component.
   d. The term of service under this Contract Service.
   e. The size of the load (in MW) served under this Contract Service.
   f. Identification of any distribution and/or transmission facilities that must be installed to serve the Contract Rate Service load and the responsibility for installation and future maintenance costs.
   g. Verification that member has been fully informed of the availability of an electric energy review. If no electric energy review is performed for the member, an explanation of why an electric energy review was not necessary will be included.

SCHEDULE 72
CONTRACT RATE SERVICE
(Continued)

1. Each member receiving service under the Contract Rate Service will be responsible for all wholesale power costs associated with their electric service. The Association will track the wholesale power costs associated with all contract rates and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Commission.
2. A rate under this Contract Service will meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other members in this same member class.
3. A rate under this Contract Service will not compete with district heating and cooling provided by a district utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, paragraph (c).
4. A rate offered under this Contract Service will not be offered to a member in whom the Association has a financial interest greater than 50 percent.
5. Contract rates must be approved by the Commission before becoming effective.

Regulatory Review
Dakota Electric must file any proposed contract rates for individual members with the Commission. Such filings will clearly identify all confidential information as trade secret with designations as specified in Minnesota Rules. The Association will at a minimum include the following information in Contract Rate filings:

1. Information required in "Miscellaneous Filings" to the Commission as specified in applicable Minnesota Rules.
2. Information included in the electric service agreement.
3. Identification of wholesale power costs and responsibility of the member for all such costs.
4. Documentation of incremental cost recovery for service to the contract rate consumer and evaluation of impact on other Cooperative members.

The Commission will approve, modify, or reject the contract rate filing under this Contract Rate Service within 90 days. If the Commission approves the contract rate, it becomes effective as agreed to by the Association and member. If the contract rate is modified by the Commission, the Commission shall issue an order modifying the contract rate subject to the approval of the Association and the member. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Association on its behalf or on behalf of the member, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the contract rate, it shall issue an order indicating the reasons for the rejection.

ADVANCED GRID INFRASTRUCTURE RIDER

Application
Applicable to bills for electric service provided under the Association's metered retail rate schedules.

Rider
There shall be included on each member's monthly bill an Advanced Grid Infrastructure (AGi) Rider adjustment. The AGi Adjustment shall be applied on a per-meter basis before any city surcharge and sales tax.

Determination of AGi Adjustment
The AGi Adjustment shall be the quotient obtained by dividing the forecasted balance of the AGi Tracker Account for each member class by the applicable meters in each member class. The AGi Adjustment may be changed annually upon a filing with the Minnesota Public Utilities Commission (Commission). The AGi Adjustment shall apply to bills rendered on and after January 1st of the year.

The AGi Adjustment for each metered retail rate schedule is:

Member Class	Monthly Fixed Charge per Meter
Residential (Schedules 31, 32, 53, 56)	$0.00
Irrigation (Schedule 36)	$0.00
Lighting (Schedule 44-5)	$0.00
Small General (Schedule 41)	$0.00
General (Schedules 46, 54)	$0.00
C&I Interruptible (Schedules 70, 71)	$0.00

Opt-Out Members will not be subject to charges under the Advanced Grid Infrastructure (AGi) Rider, See Section V, Sheet 60.0–6 0.1 for the Advanced Meter Opt-Out (AMO) Rider.

Recoverable AGi Costs shall be the annual revenue requirements associated with AGi capital costs (a) not recovered through base rates, (b) recorded in the AGi Tracker Account for the designated period, and (c) determined by the Commission to be eligible for recovery under this Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the AGi Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the AGi Adjustment shall be credited to the AGi Tracker Account.

True-Up
For each 12-month period ending December 31, a true-up adjustment to the AGi Tracker Account will be calculated reflecting the difference between the AGi Adjustment recoveries and the revenue requirements for such period. The true-up adjustment shall be calculated and included in the AGi recovery filing submitted to the Commission for the following calendar year. No carrying cost shall be applied to the AGi Tracker.

ADVANCED METER OPT-OUT (AMO) RIDER

Applicability

Applicable for residential electric service provided under the Association's metered retail rate schedules for residential members who do not want an advanced, wireless, communicating meter installed at their residence ("Opt-Out Members").

Rate

Advanced Meter Opt-Out Members are subject to a recurring monthly fee after enrollment, regardless of the quantity of meters per premise. The applicable fees for participating in Advanced Meter Opt-Out will be shown as separate line items on the Member's bill as follows:

Monthly Charge $11.45 per month

The Monthly Charge will be applied following the meter exchange. Where a meter exchange is not required, charges will be applied following affirmative Opt-Out option election or action by the Member as described in the Terms and Conditions.

Opt-Out Members will not be subject to charges under the Advanced Grid Infrastructure (AGi) Rider, See Section V, Sheet 59 for the Advanced Grid Infrastructure Rider.

Terms and Conditions

1. The Cooperative shall have the right to refuse to provide advanced meter opt-out service in either of the following circumstances:
   a) If such a service creates a safety hazard to Members or their premises, the public, or the electric utility's personnel or facilities.
   b) If a Member does not allow the Cooperative's employees or agents access to the meter at the Member's premises.
   c) If the Member has a history of meter tampering.

2. Opt-Out Provisions:
   a) Opt-Out Election: A Member must affirmatively elect to opt-out of having electric consumption metered through an advanced meter to obtain service under this AMO Rider. Members shall default to an advanced meter absent such an election. Members who do not provide reasonable access to their meter or affirmatively prevent the installation of an advanced meter shall be deemed to have elected this AMO Rider.
   b) Frequency of Election: A Member may only enroll in this AMO Rider once per twelve-month period at the same residence.
   c) Opt-In Election: At any time, Opt-Out Members may opt back into electric service with an advanced meter.
   d) Local governments and entities such as condominiums and other multi-unit dwellings are not allowed to exercise the Opt-Out option on behalf of individually metered residents.

ADVANCED METER OPT-OUT (AMO) RIDER
(Continued)

3. Metering Equipment: A non-communicating meter will be used to provide electric service for Members who elect this option.

4. Members enrolled in a load management program or other service requiring an advanced meter will be notified that the Member must discontinue participation in the load management program.

5. Estimated Meter Reading: Opt-Out Members may receive bills based on estimated meter reads if circumstances prevent reading a meter in a given month.

6. Billing: Members will be billed for charges incurred for electric consumption under the applicable metered retail rate schedule, plus the Monthly Charge described in this AMO Rider.

GENERAL RULES AND REGULATIONS

TABLE OF CONTENTS

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE

General Policies Applicable to All Extensions of Service

1. It shall be the policy of Dakota Electric Association (DEA) to provide and extend electric service to any member within its service area in accordance with the rate schedules and policies established by the Association.

2. Dakota Electric Association requires that, on overhead services, the member or developer provide all necessary tree clearing of the power line route outside the public right-of-way. Clearing includes any removal of debris as a result of tree cutting as may be required. The normal width of the right-of-way is to be cleared 10 feet on each side of the power line.

   Dakota Electric Association will provide all necessary tree trimming on new overhead service extensions within the public right-of-way.

   It is the goal of Dakota Electric Association to cooperate with the member to save as many trees as possible without jeopardizing the power line operation.

3. The member shall pay the cost of any subsequent relocation or rearrangement of any portion of the Association's system made to accommodate his/her needs or to accommodate alterations in grade.

4. Equipment, such as motors and generators that are operated interconnected with the Association, shall not cause objectionable voltage flicker on the distribution system and for other Association members. The member shall apply starters/controllers to the motors, as required, to limit the starting currents to levels acceptable to the Association. For generation, the member shall design and operate the generation system and the load transfer to and from the generation system so as not to cause objectionable voltage flicker.

5. Meters on all new installations shall meet the requirements of the Association's Technical Standards for Metering which are consistent with industry practices.

6. All member wiring must meet the requirements of the National Electric Code, National Electric Safety Code, State and local jurisdictions.

Continuity of Service

Dakota Electric Association will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of electric service. The Cooperative will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Cooperative. The Cooperative reserves the right, without previously notifying the member, to temporarily interrupt service for construction, inspection, repairs, emergency operations, shortages in power supply, safety, and State or National emergencies. The Cooperative will not be liable in any event for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Individual Residential Extensions

1. Dakota Electric Association will serve a year-round, principle residence of an individual residential member with overhead or underground single-phase electric service at the rates and minimum charges established in applicable rate schedules. In order to ensure that the cost of the new facilities will not cause an undue burden on other members, the member will be assessed a contribution in aid of construction. The member will be charged a minimum of $500.00 for an extension of 75 feet or less. For extensions longer than 75 feet, the member will be charged $500.00 plus $8.30 per foot for each foot that the extension exceeds 75 feet. The member will be assessed additional charges if above normal costs are incurred by DEA to accommodate member installation preferences or the member requests a nonstandard installation.

2. Dakota Electric Association will furnish the overhead service triplex wire between the overhead system and the member-owned service mast. If a member desires underground service, DEA will install underground primary or secondary wire between the right-of-way and a point of connection located no closer than fifty (50) feet from the building, measured from the closest point of the building to the existing DEA facilities. The consumer will be charged the line extension costs outlined in paragraph one (1) of this section.

3. The member must install and own the underground secondary wire run between the point of connection and the meter. Dakota Electric Association will make the connection required at the point of connection.

4. For underground service, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade, free from obstructions and completely accessible to the Cooperative's equipment.

5. The member will be required to obtain and/or grant easements to the Cooperative for any portion of the extension that is outside a public right-of-way or easement, at no cost to the Cooperative. The Cooperative will prepare the necessary easement documents and will be reimbursed by the member for costs incurred for property title search, surveying, and recording fees.

6. The member will pay any additional installation costs incurred by the Cooperative because of:
   a. delays caused by member:
   b. installation of underground facilities after the ground is frozen;
   c. surface and subsurface conditions that impede the installation of underground facilities, such as rock formations;
   d. paving of streets, alleys or other areas prior to the installation of the underground facility;
   e. above-average permit costs; or
   f. DNR crossing fees.

7. The member will also be responsible for costs incurred for any relocation or rearrangement of any portion of the system made to accommodate the member after construction is underway or complete. The normal service capacity provided for overhead service will be 10 KVA per residential member and 15 KVA for underground service. Residential members requesting greater transformer capacity will be considered on an individual basis to determine if anticipated revenue justifies the additional expenditure without any further contribution in aid of construction.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

8. If a member requests an individual residential service extension to a location with no permanent residence, the member will pay the full cost of installation. If a permanent residence is constructed within five (5) years, the member will be refunded the amount less the normal line extension charge at the time the permanent residence is constructed.

9. Dakota Electric Association will not install a transformer within 50 feet of the house. If the closest point of the member's house is within 150 feet of the distribution system in the public right-of-way, the member must install their own secondaries.

Residential Developments (Multiple Lot Plats)

1. To encourage orderly development and to avoid investment in idle facilities, it shall be Dakota Electric Association's policy to examine all residential developments whether served overhead or underground for justification to install electric distribution facilities. When the anticipated revenue justifies the expenditure, Dakota Electric Association will install the facilities at its expense. When the anticipated revenue does not justify the expenditure, the installation will be made only if the developer pays Dakota Electric Association that portion of the facility cost not justified by the anticipated revenue prior to commencement of the electric utility installation.

2. For developments of small lots, one acre or smaller, when underground electric service is desired by a developer or required by a regulatory body or by local ordinance, Dakota Electric Association requires the developer to sign and follow the provisions of the "Residential Underground Distribution Agreement" (RUDA-1).

3. Underground service shall be made available to platted areas with large lots by employing individual transformers for each home. Large lots are defined as being larger than one acre or any lot requiring an individual transformer.

   The developer shall also be subject to a payment in accordance with the provisions of paragraph 1 (Residential Developments) of this policy and as outlined in the Residential Underground Distribution Agreement (RUDA-1) for standard-sized lots.

   Developers of large lot plats must sign and follow the provisions of the Residential Underground Distribution Agreement for Large Lot Developments (RUDA-2).

4. The normal transformer capacity provided for large lot plats will be 15 KVA with additional capacity considered on an individual basis as outlined under paragraph 1, "Individual Overhead Service."

Lighting

The member will be charged for installation costs that exceed allowances specified in the applicable lighting rate schedule.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

Commercial and Industrial Members, Apartment Complexes, and Seasonal Accounts

1. Dakota Electric Association will provide overhead or underground, single-phase or three-phase electric service to commercial (including commercial developments) and industrial members and apartment complexes in accordance with established applicable rates and charges when the anticipated revenue justifies the expenditure. Dakota Electric Association will install, own, and maintain the underground primary service to a point of connection designated as either a single-phase or three-phase padmounted transformer. An economic analysis will be made for any service that involves abnormally high investments, and/or those with low anticipated revenue. A contribution in the aid of construction will be required if the estimated investment is not justified by the anticipated revenue, calculated as follows:

	Sched. 41 Factors	Sched. 46 Factors	Sched. 70/71 Factors
Estimated Extension Costs			
- Annual Sum of Monthly Non-Coincident Billing Demand (kW) times applicable rate schedule factor	NA	$6.25	$5.54
- Annual Sum of Monthly billed energy (kWh) times applicable rate schedule factor	$0.14779	$0.01959	$0.01326
= Required Contribution in Aid of Construction			

When underground service is requested, the member shall provide a right-of-way strip that is within four (4) inches, plus or minus, of the finished grade. The right-of-way must be free from obstructions and completely accessible to the Association's equipment.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

The member will pay any additional installation costs incurred by the Association because of:

1. delays caused by member;
2. installation of underground facilities after ground is frozen;
3. soil conditions that impair the installation of underground facilities, such as rock formations;
4. paving of streets, alleys or other areas prior to the installation of the underground facility;
5. above-average permit costs; or
6. DNR crossing fees.

There may be situations where the member shall be required to install sections of conduit, such as underground entrance to a pad, which shall be at no cost to the Association.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
CONTINUED

The 2000 KVA distribution transformer is the largest size that Dakota Electric Association will install. Multiple transformers and service entrances will be required when service capacity requirements exceed 2000 KVA. The member cannot parallel multiple transformer services without written Dakota Electric approval of the design.

2. Irrigation Members
Dakota Electric Association will provide service to irrigation members in accordance with established applicable irrigation rates and in the "Agreement for Electric Service (Irrigation and Other Seasonal Loads). An economic analysis will be made for extensions to irrigation service. A contribution in aid of construction will be required if the estimated investment is not justified by the anticipated revenue.

The member shall furnish the pad for the padmounted transformer on underground systems in accordance with specifications provided by Dakota Electric Association.

3. Primary Metered Installations
Depending on the configuration of the Dakota Electric primary system, the member may have the option of installing primary metering on the 12.5kV system. Credits for primary service may be available as specified in applicable rate schedules. Many times this option is not available without the installation of additional 12.5kV facilities so as to allow for proper metering and so as not to negatively impact the reliability of other Dakota Electric member loads interconnected with the Dakota Electric distribution system.
   A. The member is responsible for all integration and installation costs for the primary metering system.
   B. The member is responsible for purchasing, owning and operating, all 12.5kV electrical facilities on the member's side of the primary metering installation(s). This includes responsibility for routine and emergency maintenance of those purchased primary facilities, which includes emergency transformer replacement and emergency primary facility repairs.
   C. Primary Metering is required for all primary wires feeding the facilities/complex.
   D. Dakota Electric, the National Electric Code, or both may require special protection for the member's primary system. The member is required to provide any necessary protection. This protection is required to be coordinated with the DEA distribution system's protection.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES

A. Definitions

1. Municipality is defined as any one of the following entities: a county, a city, a township or any other unit of local government.

2. City is defined as either a statutory city or home rule charter city consistent with Minn. Stat. sections 410.015 and 216B.02, subd. 9.

3. Special facilities are defined as non-standard facilities, non-standard design or non-standard location of facilities.

4. Special facilities are the type of services that results in costs in excess of the Association designated service installation. Common examples are duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is adequate, excess capacity, underground installations to wood poles, conversion from overhead to underground service, specific area undergrounding, other special undergrounding, and relocation or replacement of existing Association facilities.

B. General Rule

When requested by the member, group of members, developer, or municipality to provide types of service that result in an expenditure in excess of the Association designated service installation the requesting member, group of members, developer, or municipality will be responsible for such excess expenditure. Common examples of these requests are duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is adequate, excess capacity, capacity for intermittent equipment, trailer park distribution systems, underground installations to wood poles, conversion from overhead to underground, urban renewal undergrounding, other special undergrounding, and relocation or replacement of existing Association facilities.

C. Public Right-of-Way

1. Replacement, Modification or Relocation Due to Construction.

Whenever a governing body that manages a public right-of-way orders the Association to replace, modify or relocate its existing distribution facilities due to construction on said public right-of-way, such facilities will be relocated at Association expense, provided the construction is the most economical, industry accepted installation designated by the Association. If the governing body or municipality requests a type of construction with

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

costs in excess of the Association designated construction, such excess expenditures will be the responsibility of the municipality or the Association's members residing within the municipality. However, if the governing body issuing the order requiring construction on the public right-of-way does not pay the excess cost, the Association may seek Commission approval to recover such excess expenditures from the ratepayers residing in the governing body's territory.

2. Replacement, Modification or Relocation Due to Vacation of Public Right-of-Way.

Whenever a governing body of public right-of-way orders the Association to replace, modify or relocate its existing distribution facilities due to a vacation of a public right-of-way, the Association will be responsible for such expenditure. The Association may request that the governing body pay for the aforementioned expenditure. However, if the governing body chooses not to pay, the Association may seek approval from the Commission to recover this expenditure from the ratepayers residing in the governing body's territory.

D. Construction Requirements for Special Facilities

The Association will initially install special distribution facilities (which may include installation of standard facilities at a location/route deemed non-standard by the company) or the Association will replace, modify or relocate to an Association-approved location/route its existing distribution facilities upon a request of a member, group of members, developer, or upon order or request of a municipality. The benefited member, group of members, developer or municipality will be responsible for all costs in excess of standard installation for new facilities plus the value of the undepreciated life of existing facilities being removed minus the salvage value. However, if the municipality does not pay for the excess expenditure, the Association may seek Commission approval to recover such expenditure from the requesting municipality.

E. Underground Facilities Requirements

The following provisions apply when replacing overhead facilities with underground facilities:

1. The member, at their expense, must engage an electrician to adapt their electrical facilities to accept service from Association underground facilities.

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

2. The Association will allow reasonable time for the member to make the necessary alterations to their facilities, before removal of the existing overhead facilities.
3. Perpetual easements will be granted to Association at no cost to the Association whenever any portion of the underground distribution system is located on private land. Said private easements also will allow the Association access for inspection, maintenance, and repair of Association facilities.
4. The Association will have full access to its facilities installed underground for the purpose of inspection, maintenance, and repair of such facilities, such right of access to include the right to open streets and alleys.
5. When undergrounding is the result of a municipal project, the municipality will designate and reserve a definite area within the public ways for the installation and location of Association underground facilities. Once the Association facilities have been installed in such designated and reserved areas, if the municipality requires removal or relocation of such facilities for any reason, the municipality will reimburse the Association for the cost of such removal or relocation. However, if the municipality does not pay for the aforementioned expenditure, the Association may seek approval from the Commission to recover this expenditure from the ratepayers residing in the municipality’s territory.
6. The municipality will give sufficient notice and will allow the Association sufficient time to place its facilities beneath public ways while the same are torn up for resurfacing. The municipality shall provide Association with access to the torn up public ways during such period so that Association will have unobstructed use of sufficiently large sections of the public ways to allow installation of the underground facilities in an economic manner.
7. Secondary voltage service supplied from an underground distribution lateral installation will require that the member install, own, and maintain necessary conduits and secondary service conductors or bus duct to a point designated by Association within or adjacent to the secondary compartment of the transformer or vault. Association will make final connection of member’s secondary service conductors or bus duct to Association’s facilities.
8. Secondary voltage service supplied from underground secondary service conductors may require that the member install, own, or maintain necessary conduits on private property to a point designated by the Association at or near the property line. The secondary service conductors usually will be installed by the member in his conduit,

MEMBER SERVICE INFORMATION
EXTENSION OF SERVICE
SPECIAL FACILITIES
(Continued)

However, in some installations it may be preferred to have Association provide a continuous installation from the Association facilities through the member conduit to his service equipment. In these installations the member must pay the total installed cost of the Association's cable installed on private property. The Association will make the final connection of member's secondary service connectors to Association's facilities.

F. Special Facilities Payments

The requesting party shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment of the facilities. Payments required will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing by the Association. The facilities installed by the Association shall be the property of the Association. Any payment by a member, group of members, developer or municipality shall not entitle him to any ownership interest or rights therein.

Payment for special facilities may be required by either, or a combination, of the following methods as prescribed by the Association: a single charge for the costs incurred or to be incurred by the Association due to such a special installation or a monthly charge being one-twelfth of Association's annual fixed costs necessary to provide such a special installation. The monthly charge will be discontinued if the special facilities are removed. When special distribution facilities are requested by a municipality and payment is not made by the municipality, the Association may seek approval from the Commission to recover its excess expenditure from the municipality's ratepayers.

MEMBER SERVICE INFORMATION
TEMPORARY SERVICE

Temporary service installation will be permitted during the period of construction, remodeling, maintenance, repair, or demolition of buildings, structures, equipment, or similar activities. When installing temporary service to a member, Dakota Electric Association will require that the member bear the cost of the installation and removal of service in excess of any salvage realized.

The member receiving temporary service will be charged the regular rates applicable to the service rendered.

Dakota Electric Association may require that advance payment be made to cover the estimated cost of the temporary service.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS

Meter Reading and Billing Periods

The reading of all meters used for determining charges to members shall be made each month unless otherwise specified by Dakota Electric Association.

The term "month" for meter reading and billing purposes is the period between successive meter readings, which shall be as near as practicable to 30 days.

Dakota Electric Association requires access to meters monthly unless other arrangements are made to obtain monthly meter readings.

If a billing period is longer or shorter than a normal billing period by five (5) days, the billings shall be prorated on a daily basis.

Estimated Billings

When access to a meter cannot be gained, an estimated bill may be rendered. In cases of emergency, the Dakota Electric Association may render estimated bills without reading meters. Estimated bills shall be based on the member's normal consumption for a corresponding period during the preceding months.

Only in unusual cases, or when approval is obtained from the member, shall more than two (2) consecutive estimated bills be rendered.

If an estimated bill seems to be abnormal when a subsequent reading is obtained, the bill, or bills, for the entire estimated period shall be recalculated and a corrected bill generated. If there is reasonable evidence that the use occurred during only one (1) billing period, the bill shall be so computed.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS
(Continued)

Payment of Electric Bills

Residential Members. Residential bills shall be due not less than 25 days from the current billing date. The current billing date shall be no more than three working days before the date of mailing. Balances over $10.00 not received by Dakota Electric by the due date will have a monthly late fee of 1.5 percent or $1.00, whichever is greater, added to the balance.

All Other Members. Bills for all other members shall be rendered monthly and shall be due not less than 15 days from the billing date. The current billing date shall be no more than three (3) working days before the date of mailing. Balances over $10.00 not received by Dakota Electric by the due date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

Payment of Bills by Check

It will be the policy of the Association to accept checks in payment of the electric bill. When a question arises as to the validity of a personal check, cash or money order may be required. No second party or postdated checks will be accepted.

If a check is not honored because of "insufficient funds" or for any other reason, a service charge will be assessed, and the status of the account will be the same as if no payment had been made.

When a payment is made by personal check in order to avoid termination of service, and the check is not honored, service may be disconnected without further notice.

Payment by check or debit card will not be honored for reconnection after disconnection for non-payment. Payment for reconnection after disconnection for non-payment must be made by cash, credit card, or money order.

MEMBER SERVICE INFORMATION
BILLING AND PAYMENT OF ELECTRIC BILLS
(Continued)

Budget Payment Plan
Dakota Electric Association shall have a budget payment plan available to residential and farm members designed to level monthly billings. The Association will establish a fixed monthly billing based on previous usage. Each monthly bill will show the relationship of budget payments made to the amount due based on actual usage.

Late charges will be assessed to the lesser of the outstanding account balance or the scheduled monthly payment.

Dakota Electric Association will review all budget payment accounts at least annually.

Electronic Funds Transfer
Dakota Electric Association has an Electronic Funds Transfer program (EFT) available to all members. Members may authorize monthly withdrawals for their electric bills directly from their designated financial institutions.

If a presented payment is not honored, late fees and service charges will be billed in accordance with existing policies. EFT can be terminated in writing by either the Association or the member at any time.

Credit Card Payment
Through a third-party vendor, Dakota Electric Association offers all members the option to pay their electric bill by credit card. The member opts to pay a transaction fee based on the amount of the payment. The transaction fee is collected and retained entirely by the third-party vendor.

If a presented payment is not honored, late fees and service charges will be billed to the member in accordance with existing policies.

QuikPay Online Payment
Dakota Electric offers members the option of making either a one-time online payment or regular online monthly payments through "QuikPay". QuikPay provides multiple payment options. Members may manually enter payments online each month from a checking, savings, or credit card (credit card payments subject to a convenience fee). Members may also have funds automatically deducted from checking or savings accounts.

MEMBER SERVICE INFORMATION
SERVICE CHARGE

When Dakota Electric Association sends a two-man crew or larger to a consumer's premise on a service call outside normal working hours, and they find the trouble is not with Dakota Electric's equipment, a service charge may be assessed.

Every effort to clarify the trouble by telephone shall be made by Dakota Electric Association personnel before they make the trip out to the consumer's premise.

MEMBER SERVICE INFORMATION

Meter Testing

The Cooperative will maintain and test its metering equipment in accordance with the Public Utilities Commission's rules. In the event the Cooperative's test shows a meter to have an average error of more than 2% fast or slow, the Cooperative shall make an adjustment of the bills for service during the period of registration error if known, but not longer than a period of one year. If the period of registration error is not known, the refund or charge for both fast and slow meters shall be based on corrected meter readings for a period equal to one-half the time elapsed since the last test but not to exceed six months. If the amount of the average meter error cannot be determined because of failure of part or all of the metering equipment, the consumer shall pay an amount based upon registration of check metering equipment or an estimated amount based upon the consumer's consumption for comparable operations over a similar period.

If a consumer has called to the Cooperative’s attention doubts as to the meter's accuracy and the Cooperative has failed within a reasonable time to check it, there shall be no back billing for the period between the date of the consumer’s notification and the date the meter was checked.

Billing Corrections

When a consumer has been overcharged/undercharged as a result of an incorrect reading of the meter, incorrect application of the rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant, or other similar reasons, the amount of the overcharge/undercharge shall be adjusted, refunded, or credited to the consumer as follows:

Remedy for Overcharge:
Dakota Electric shall calculate the difference between the amount collected for service and the amount the Cooperative should have collected for service, plus interest, for the period beginning three years before the date of discovery. Interest will be calculated as prescribed by Minnesota Statutes §325E.02(b). If the recalculated bills indicate that more than $1 is due an existing consumer, or $2 is due a person no longer a consumer of the Cooperative, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the consumer. Refunds to an existing consumer may be in cash or credit on a bill. Credits shall be shown separately and identified. If a refund is due a person no longer a consumer of the Cooperative, the Cooperative shall mail to the consumer’s last known address either the refund or a notice that the consumer has three months in which to request a refund from the Cooperative.

Remedy for Undercharge:
Dakota Electric shall calculate the difference between the amount collected for service and the amount the Cooperative should have collected for service for the period beginning one year before the date of discovery. If the recalculated bills indicate that the amount due the Cooperative exceeds $10, the Cooperative may bill the consumer for the amount due. Dakota Electric must not bill for any undercharge incurred after the date of a consumer inquiry or complaint if the Cooperative failed to begin investigating the matter within a reasonable time and the inquiry or complaint ultimately resulted in the discovery of the undercharge. The billing for undercharges shall be separated from the regular bill and the charges explained in detail.

Exception if error date is known:
If the date the error occurred can be fixed with reasonable certainty, the remedy shall be calculated on the basis of payments for service after that date, but in no event for a period beginning more than three years before the discovery of an overcharge or one year before the discovery of an undercharge.

MEMBER SERVICE INFORMATION

General Payment Arrangements

In compliance with Minn. Stat. §216B.098, the Cooperative shall offer a payment agreement for the payment of arrears. Payment agreements will consider a consumer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to continue service to a consumer who has entered and is reasonably on time under an accepted payment agreement.

Undercharges:

a. In compliance with Minn. Stat. §216B.098, the Cooperative shall offer a payment arrangement to consumers who have been undercharged if no culpable conduct by the consumer or resident of the consumer's household caused the undercharge. The agreement may cover a period equal to the time over which the undercharge occurred, or a different time period that is mutually agreeable to the consumer and the Cooperative, except that the duration of a payment agreement offered by the Cooperative to a consumer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the consumer's household.

b. No interest or delinquency fee will be charged for payment arrangements resulting from under charges.

c. If a consumer inquiry or complaint results in the Cooperative's discovery of the undercharge, the Cooperative may bill for undercharges incurred after the date of the inquiry or complaint only if the Cooperative began investigating the inquiry or complaint within a reasonable time after when it was made.

Medically Necessary Equipment

The Cooperative shall reconnect or continue service to a consumer's residence where a medical emergency exists, or where medical equipment requiring electricity necessary to sustain life is in use, provided that the Cooperative receives: (1) written certification, or initial certification by telephone and written certification within five business days, from a medical doctor that failure to reconnect or continue service will impair or threaten the health or safety of a resident of the consumer's household; and (2) the consumer's consent to a payment arrangement for the amount in arrears. Certification must be renewed annually. Because some interruptions in service are unavoidable and in some cases may last longer than some members can be without power, we urge members with special medical needs to make necessary arrangements for auxiliary power for any vital life-support equipment.

MEMBER SERVICE INFORMATION
DISCONNECTION OF SERVICE

Disconnection Without Notice

Without notice Dakota Electric may disconnect service to any consumer:

A. in the event of an unauthorized use of or tampering with the Association's equipment; or
B. in the event of a condition determined to be hazardous to the consumer, to other members of the Association, to the Association's equipment, or to the public.

Unlawful Use of Service

In any case of tampering with meter installation or interfering with the proper functioning thereof or any other unlawful use or diversion of service by any person, or evidence of any such tampering, interfering, unlawful use or service diversion, consumer is liable to immediate discontinuance of service, without notice, and to prosecution under applicable laws, and Association shall be entitled to collect from consumer at the appropriate rate for all power and energy not recorded on the meter by reason of such tampering, interfering, or other unlawful use or service diversion (the amount of which may be estimated by Association from the best available data), and also for all expenses incurred by the Association on account of such unauthorized act or acts.

Disconnection for Nonpayment

<u>All Accounts</u>

Dakota Electric shall credit all payments received against the oldest outstanding account balance before the application of any late charge.

<u>Residential Accounts</u>

In the case of a resident on either a budget billing plan or a payment schedule, delinquent amount means the lesser of the outstanding account balance or the outstanding scheduled payments. To avoid disconnecting residential accounts as much as possible, Dakota Electric will advise delinquent residential members of the various alternatives available to them, such as protection of the Cold Weather Rule when applicable (see below) and the various assistance programs available through state and local agencies. When no satisfactory payment schedule can be agreed to or maintained, Dakota Electric will proceed with disconnection. The schedule will be as follows:

Balances over $10.00 not received by Dakota Electric at the time of the next scheduled billing date (approximately 30 days after initial billing and never less than 25 days later) will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance. A disconnect notice may be sent shortly after the second bill is mailed. Disconnection will be scheduled for not less than five (5) days after the date of the disconnect notice. At the time of disconnection, the residential account will have unpaid use of electricity for not less than 50 days.

<u>Commercial and Irrigation Accounts</u>

Balances over $10.00 not received by Dakota Electric at the time of the next scheduled billing date (approximately 30 days after initial billing and never less than 25 days later) will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance. A disconnect notice will be sent shortly after the second bill is mailed. Disconnection will be scheduled for five (5) days after the date of the disconnect notice. At the time of disconnection, the commercial account will have unpaid use of electricity for approximately 50 days.

MEMBER SERVICE INFORMATION
DISCONNECTION OF SERVICE

Notice of Disconnection

Dakota Electric Association shall send notices to disconnect service by first class mail. A specific date will be given for the time when a payment must be received or service may be disconnected.

If Dakota Electric Association is not contacted by the consumer, at least one attempt will be made to contact the consumer by telephone. If no contact is made, an Association employee will make a final attempt to contact the consumer at the place of service, and if no contact is made, or if contact is made but no payment agreement can be reached, service may be disconnected.

Reconnection of Service

In the event that service has been disconnected because of nonpayment of the electric bill, service charges, based on the cost to restore service will be assessed before service is restored. This cost will necessarily be higher during an overtime period.

If service has been disconnected, payment must be in the office before the order will be given to restore service. Cash or money order may be required at any time. Dakota Electric will not restore service until all arrears are paid in full and a deposit is made by cash, credit card, or money order according to the Association's deposit requirements, or until other satisfactory credit arrangement is made.

In the event the order has been issued to disconnect service, and the collector arrives at the premises, he/she must accept cash, credit card, or money order payment of the delinquent bill. This payment will avoid the necessity of terminating service.

Notice to Cities of Utility Disconnection

Upon written request from a statutory or home rule charter city and consistent with Minnesota Statute 216B.0976, the Cooperative will provide reports of currently disconnected properties or newly disconnected properties for consumers located within the city's boundaries.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SECTION: VI
SHEET: 14.0
REVISION: Original

DISCONNECTION DURING COLD WEATHER
(Page 1 of 6)

1. Scope

This section applies only to residential consumers of the Cooperative.

2. Definitions

The following definitions apply in this section:

1. "**Cold weather period**" means the period from October 15 through April 15 of the following year.
2. "**Consumer**" means a residential consumer of the Cooperative.
3. "**Disconnection**" means the involuntary loss of utility heating service as a result of a physical act by the Cooperative to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts utility service in any way.
4. "**Household income**" means the combined income, as defined in section 290A.03, subdivision 3, of all residents of the consumer's household, computed on an annual basis. Household income does not include any amount received for energy assistance.
5. "**Reasonably timely payment**" means payment within five working days of agreed-upon due dates.
6. "**Reconnection**" means the restoration of utility heating service after it has been disconnected.
7. "**Summary of rights and responsibilities**" means a notice approved by the Minnesota Public Utilities Commission that contains, at a minimum, the following:
    a) an explanation of the provisions of Section 5 and Minn. Stat. 216B.096, subd. 5;
    b) an explanation of no-cost and low-cost methods to reduce the consumption of energy;
    c) a third-party notice;
    d) ways to avoid disconnection;
    e) information regarding payment agreements;
    f) an explanation of the consumer's right to appeal a determination of income by the Cooperative and the right to appeal if the Cooperative and the consumer cannot arrive at a mutually acceptable payment agreement; and
    g) a list of names and telephone numbers for county and local energy assistance and weatherization providers in each county served by the Cooperative.

DISCONNECTION DURING COLD WEATHER
(Page 2 of 6)

1. "**Third-party notice**" means a Minnesota Public Utilities Commission-approved notice containing, at a minimum, the following information:
   a) a statement that the Cooperative will send a copy of any future notice of proposed disconnection of Cooperative service to a third party designated by the residential consumer;
   a) instructions on how to request this service; and
   b) a statement that the residential consumer should contact the person the consumer intends to designate as the third-party contact before providing the Cooperative with the party's name.
2. "**Cooperative**" means Dakota Electric Association.
3. "**Utility heating service**" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the consumer's primary residence.
4. "**Working days**" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing of a notice shall not be counted in calculating working days.

3. Cooperative obligations before cold weather period

Each year, between September 1 and October 15, the Cooperative must provide all consumers, personally or by first class mail, a summary of rights and responsibilities. The summary must also be provided to all new residential consumers when service is initiated.

4. Notice before disconnection during cold weather period

Before disconnecting utility heating service during the cold weather period, the Cooperative must provide, personally or by first class mail, a Minnesota Public Utilities Commission-approved notice to a consumer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of rights and responsibilities.

DISCONNECTION DURING COLD WEATHER
(Page 3 of 6)

5. Cold weather rule

During the cold weather period, the Cooperative may not disconnect and must reconnect utility heating service of a consumer whose household income is at or below 50 percent of the state median income if the consumer enters into and makes reasonably timely payments under a mutually acceptable payment agreement with the Cooperative that is based on the financial resources and circumstances of the household; provided that, the Cooperative may not require a consumer to pay more than ten percent of the household income toward current and past utility bills for utility heating service.

The Cooperative may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the consumer.

The consumer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the consumer's financial circumstances have changed or the consumer is unable to make reasonably timely payments.

The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the consumer and the Cooperative.

The Cooperative shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration consumer availability, employee availability, and construction-related activity.

6. Verification of income

In verifying a consumer's household income, the Cooperative may:

(1) accept the signed statement of a consumer that the consumer is income eligible;

(2) obtain income verification from a local energy assistance provider or a government agency;

(3) consider one or more of the following:

a) the most recent income tax return filed by members of the consumer's household;
b) for each employed member of the consumer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;

DISCONNECTION DURING COLD WEATHER
(Page 4 of 6)

a) documentation that the consumer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension provider;
b) a letter showing the consumer's dismissal from a job or other documentation of unemployment; or
c) other documentation that supports the consumer's declaration of income eligibility.

A consumer who receives energy assistance benefits under any federal, state, or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

7. Prohibitions and requirements

This section applies during the cold weather period.

The Cooperative may not charge a deposit or delinquency charge to a consumer who has entered into a payment agreement or a consumer who has appealed to the Minnesota Public Utilities Commission under Section 8 and Minn. Stat. 216B.096, subd. 8.

The Cooperative may not disconnect service during the following periods:

(1) during the pendency of any appeal under Section 8 and Minn. Stat. 216B.096, subd. 8;

(2) earlier than ten working days after the Cooperative has deposited in first class mail, or seven working days after the Cooperative has personally served, the notice required under Section 4 to a consumer in an occupied dwelling;

(3) earlier than ten working days after the Cooperative has deposited in first class mail the notice required under Section 4 and Minn. Stat. 216B.096, subd. 4 to the recorded billing address of the consumer, if the Cooperative has reasonably determined from an on-site inspection that the dwelling is unoccupied;

(4) on a Friday, unless the Cooperative makes personal contact with, and offers a payment agreement consistent with this section to the consumer;

(5) on a Saturday, Sunday, holiday, or the day before a holiday;

(6) when Cooperative offices are closed;

DISCONNECTION DURING COLD WEATHER
(Page 5 of 6)

(7) when no Cooperative personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service; or

(8) when the Minnesota Public Utilities Commission offices are closed.

The Cooperative may not discontinue service until the Cooperative investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the Cooperative to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the Cooperative must attempt a second contact during nonbusiness hours. If personal contact is made, the Cooperative representative must provide notice required under Section 4 and Minn. Stat. 216B.096, subd. 4 and, if the Cooperative representative is not authorized to enter into a payment agreement, the telephone number the consumer can call to establish a payment agreement.

The Cooperative must reconnect utility service if, following disconnection, the dwelling is found to be occupied and the consumer agrees to enter into a payment agreement or appeals to the Minnesota Public Utilities Commission because the consumer and the Cooperative are unable to agree on a payment agreement.

8. Disputes; consumer appeals

The Cooperative must provide the consumer and any designated third party with a Minnesota Public Utilities Commission-approved written notice of the right to appeal:

(1) a Cooperative determination that the consumer's household income is more than 50 percent of state median household income; or

(2) when the Cooperative and consumer are unable to agree on the establishment or modification of a payment agreement.

A consumer's appeal must be filed with the Minnesota Public Utilities Commission no later than seven working days after the consumer's receipt of a personally served appeal notice, or within ten working days after the Cooperative has deposited a first class mail appeal notice.

DISCONNECTION DURING COLD WEATHER
(Page 6 of 6)

Notwithstanding any other law, following an appeals decision adverse to the consumer, the Cooperative may not disconnect utility heating service for seven working days after the Cooperative has personally served a disconnection notice, or for ten working days after the Cooperative has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

9. Consumers above 50 percent of state median income

During the cold weather period, a consumer whose household income is above 50 percent of state median income:

(1) has the right to a payment agreement that takes into consideration the consumer's financial circumstances and any other extenuating circumstances of the household; and

(2) may not be disconnected and must be reconnected if the consumer makes timely payments under a payment agreement accepted by the Cooperative.

The second sentence of Section 7 does not apply to consumers whose household income is above 50 percent of state median income.

10. Reporting

Annually on November 1, the Cooperative must electronically file with the Minnesota Public Utilities Commission a report, in a format specified by the Minnesota Public Utilities Commission, specifying the number of utility heating service consumers whose service is disconnected or remains disconnected for nonpayment as of October 1 and October 15. If consumers remain disconnected on October 15, the Cooperative must file a report each week between November 1 and the end of the cold weather period specifying:

(1) the number of utility heating service consumers that are or remain disconnected from service for nonpayment; and

(2) the number of utility heating service consumers that are reconnected to service each week. The Cooperative may discontinue weekly reporting if the number of utility heating service consumers that are or remain disconnected reaches zero before the end of the cold weather period.

The data reported under this Section and Minn. Stat. 216B.096 are presumed to be accurate upon submission and must be made available through the commission's electronic filing system.

MEMBER SERVICE INFORMATION
DEPOSITS

It will be the policy of Dakota Electric Association to collect a deposit not to exceed an estimated two months' gross bill or existing two months' average bill where applicable if the service has been terminated because of nonpayment or when a bankruptcy is filed. Any existing deposit must be applied to the delinquent bill, and then the new deposit will be assessed and must be paid prior to the time the service is restored.

When a member returns to Dakota Electric Association after leaving with an unpaid balance or other credit problems, a deposit equal to two average months' electric bills of the most recent occupant at that address may be assessed. This deposit is in addition to payment in full for the previously unpaid balance.

Dakota Electric shall not require a deposit for a new member with no prior service from the Association unless the credit history of the new member demonstrates that payment cannot be assured. The determination of the new member's credit history shall be made only by credit reports reflecting the purchase of utility service, unless permission in writing is received from the new member to use other credit reports, and such reports mailed to the new member. Refusal of a new member to permit use of a credit rating or credit service, other than that of a utility, shall not affect the Association's determination of that new member's credit history. Satisfactory credit shall be 12 consecutive months of on-time payments with no remaining unpaid balance.

If a member has maintained a good payment record for one year, the deposit will be refunded. A good payment record is defined as payment of the electric bill within 25 days of the due date each of the preceding 12 months.

Deposits shall earn interest at an annual rate as specified by Minnesota Statute 325E.02. This interest will be credited to the electric bill printed in December or will be credited to the final bill, whichever occurs first.

Deposits, plus interest, will be applied to the final bill, and any credit balance remaining will be refunded within forty-five (45) days from the date service is terminated.

Dakota Electric shall not require a deposit of any member without explaining in writing why that deposit or guarantee is required.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM

Any Dakota Electric Association member allowing Demand-Side Management (DSM) controls on approved interruptible loads will receive an off-peak energy kilowatt-hour and/or demand kilowatt charge for that electricity as listed in the rates.

General Rules and Policies

1. Dakota Electric Association shall supply additional meters and the DSM receivers at no cost to the member. All other requirements, such as the meter sockets, wiring, and installation shall be the responsibility of the member. The DSM receivers will remain the property of Dakota Electric Association. Only authorized DEA employees shall have the authority to break the seals for any reason, including repair of the DSM receivers or metering equipment.
2. DSM receivers and submeters shall be mounted adjacent to the existing kilowatt-hour meter. The meter shall be mounted on the outside of the building and shall be accessible to the Association at all times and comply with the Association meter socket requirements. Any alternate locations must be approved by the Association prior to installation.
3. Dakota Electric will make a final inspection after all of the necessary work has been done. At that time, if all equipment is functioning properly, the second meter will be installed, if required, and the controlled rate will apply. All installations must have an electrical inspection affidavit filed with the Minnesota State Board of Electricity and DEA.
4. All trouble calls dealing with the controlled loads shall be made to DEA. DEA will determine whether to send out a DEA service technician or request that the member call a service company on his/her own behalf. If the member's service technician determines that DEA's DSM receiver was malfunctioning and a DEA service technician verifies that, Dakota Electric Association will reimburse the member for the service call. If the problem is with the member's wiring or equipment, then the member will be responsible for costs incurred which may include a Load Management Service Charge.
5. All members with DSM-controlled loads shall allow periodic inspections of the controlled loads by Dakota Electric.
6. If any part of the controlled system is tampered with, the member is subject to being removed from the controlled rate for at least one (1) year.
7. Eligibility of participating loads will be guided by Great River Energy program requirements.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Controlled Water Heaters

1. The member may choose to have service under either Schedule 51, "Controlled Energy Storage," or Schedule 52, "Controlled Interruptible Service."

2. Under Schedule 51, "Controlled Energy Storage":
   a. Typically, the water heater will be energized from 11 p.m. to 7 a.m.
   b. There is no restriction on the size of the water heater, but Dakota Electric recommends an energy factor of .90 or greater and a minimum capacity of 80 gallons and larger capacity when usage and/or family size requires. DEA will assist members with sizing water heaters.
   c. All kilowatt-hours shall be submetered. If the member has other qualifying loads, these kilowatt-hours may be combined on one meter.

3. Under Schedule 52, "Controlled Interruptible Service":
   a. The member should recognize that the water heater may be off daily for extended periods, and this may result in occasional lack of sufficient hot water. The member must have an electric water heater with a minimum capacity of at least 40 gallons. Dakota Electric recommends an energy factor of .90 or greater.
   b. All kilowatt-hours shall be submetered, where feasible, or a monthly credit will be given, as listed in Schedule 52, at DEA's option. If the member also has a dual fuel heating installation, these kilowatt-hours may be combined on one submeter.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Interruptible Installations

1. Schedule 52, “Controlled Interruptible Service,” is available to members who use electricity as a heating source or other qualifying loads. Connected fixed electric space heating must be sized according to space heating requirements. Cord and plug electric space heating does not qualify.

2. Dakota Electric Association requires that a backup heat source capable of keeping the residence at a minimum of 55 degrees be present. Dakota Electric does not specify what the heat source should be except that it shall not be uncontrolled electric heat.

3. Heat pumps qualify for the interruptible rate. All electric resistance heat associated with the heat pumps must also be controlled. Heat pumps will be controlled both winter and summer in accordance with Dakota Electric’s load control requirements.

4. All kilowatt-hours shall be submetered. If the member also has a water heater or other interruptible load on Schedule 52, these kilowatt-hours may be combined on one submeter. If the member has both Interruptible and Storage loads these loads may be combined under the rate schedule with the largest load.

Energy Storage Installations

1. Schedule 51, “Controlled Energy Storage,” is available to members who normally use electricity between 11 p.m. and 7 a.m. (or as established by the Association) to charge equipment which will retain the energy for use during the remaining hours. Water, ice, slab storage, storage bricks, storage batteries, or other materials that qualify may be used for energy storage.

2. All kilowatt-hours shall be submetered. If the member also has a water heater or other energy storage load on Schedule 51, these kilowatt-hours may be combined on one submeter. If the consumer has both Interruptible and Storage loads, these loads may be combined under the rate schedule with the largest load.

MEMBER SERVICE INFORMATION
DEMAND-SIDE MANAGEMENT PROGRAM
CONTINUED

Irrigation Loads

1. The controlled rate, as listed under Schedule 36, "Irrigation Service," is available to members who have DSM equipment installed. New installations may qualify for this rate when installed.

2. Members that switch from Interruptible to Firm service during the calendar year will be billed the Firm service rate during the month the change was made. The member must remain on the Firm service rate for the remainder of the calendar year. This includes members that intentionally bypass the load control equipment.

3. The Demand-Side Management receivers will interrupt power to the pump motor, and the motor will require manual restart. Any additional equipment necessary to shut down other parts of the irrigation system must be installed by the member at their cost.

4. The typical number of hours to be controlled during any 24-hour period will be approximately six (6) hours. It may be longer based on electric system requirements.

Controlled Central Air Conditioners

1. The member may choose to have service under Schedule 80, "Cycled Air Conditioning Service," Schedule 51, "Controlled Energy Storage," or Schedule 52, "Controlled Interruptible Service,"
2. Under Schedule 80 "Cycled Air Conditioning Service"
   a. For members without other interruptible or controllable loads, such as an electric water heater, electric heat, heat pump, etc.
   b. The central air conditioner will be cycled on and off when a peak or critical situation is reached.
   c. Energy consumption may be submetered.
   d. The member should recognize that the central air conditioner may be cycled for extended periods and this may result in a temperature rise within the home.
3. Under Schedule 51 "Controlled Energy Storage" or Schedule 52 "Controlled Interruptible Service"
   a. All kilowatt-hours will be submetered. If the member also has an interruptible water heater or heat installation, these kilowatt-hours may be combined on one submeter.
   b. The central air conditioner will be cycled on and off when a peak or critical situation is reached.
   c. The member should recognize that the central air conditioner may be cycled for extended periods and this may result in a temperature rise within the home.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

MEMBER SERVICE INFORMATION
STANDBY SERVICE RIDER

STANDBY, SUPPLEMENTARY, EMERGENCY AND INCIDENTAL SERVICES

Unless otherwise specifically provided, the Association's rate schedules require that the member will take their entire electrical requirements from the Association. The Association's service is not available for standby, supplementary, emergency or incidental service with respect to any other source of power except when contracted for under a rate schedule providing for these services.

A. Definitions:

1. Standby service is defined as service continuously available through a permanent connection to provide power and energy for use by a member in case of failure of another mechanical or electrical source of power.
2. Supplementary service is defined as service continuously available through a permanent connection to supplement or augment directly or indirectly another independent source of power.
3. Emergency service is defined as service supplied through a temporary connection for the member's use when their usual source of supply has failed.
4. Incidental service is defined as service continuously available through a permanent connection to provide power and energy for use by a member where such use is merely incidental to members operations and essentially for their convenience; e.g. (without limiting the generality of the foregoing), for voltage or frequency control, for partial lighting of selected or limited areas, or for the operation of controls, battery chargers, starting devices, electric clocks, or other equipment requiring relatively small quantities of energy as compared with member's total energy usage.

B. Parallel Operations. If a member has an independent source of power that will be operated in parallel with the Association's system, such source of power must be operated as provided below. Any member who operates their facility in non-compliance with these provisions will be subject to immediate discontinuance of service.

MEMBER SERVICE INFORMATION
STANDBY SERVICE RIDER
CONTINUED

1. No member may connect an independent source of power in parallel with the Association's system without prior written consent of the Association. Any member desiring to generate in parallel shall execute a contract with the Association that contains terms and provisions regarding metering, billing, technical and operating parameters for the member's independent source of power.

2. The interconnection of member's facilities with the Association's system shall not interfere with the quality of the Association's service to any of its other members.

3. The member will provide the necessary equipment as approved by the Association to enable the member to operate their independent source of power in parallel with the Association's system. The member's independent source of power will be designed so that the interconnection circuit breaker or load break switch between the Association and the member will open under the following conditions:

    a. De-energized Association system
    b. Sustained line faults on Association's system
    c. Faults on member's system

A member shall consult with the Association regarding these minimum requirements, additional protection recommended, proper operation of interconnect circuit breaker or load break switch, and member's independent source of power disconnecting device.

4. Since the power factor and the voltage at which the Association's system and a member's system are operated will vary, each party agrees to operate their system at a power factor as near unity as possible in such manner as to absorb their share of the reactive power, and voltage as conducive to the best operating standards.

5. The Association reserves the right to discontinue service if continued parallel operation by the member results in trouble on the Association's system, such as interruptions, ground faults, radio or telephone interference, surges, or objectionable voltage fluctuations, where such trouble is caused by a member and the member fails to remedy the causes thereof within a reasonable time.

MEMBER SERVICE INFORMATION
INTERRUPTIBLE SERVICE (SCHEDULES 70 AND 71)

A. General Rules and Policies for Interruptible Service (Schedules 70 and 71)

Participation in interruptible service, with or without a generator, must comply with the following requirements as applicable. If a generation system is used for curtailing a member's electrical requirements, the generation interconnection must comply with the requirements specified in the "Dakota Electric Association Distributed Generation Interconnection Requirements" document. The process for interconnecting with the Dakota Electric systems is documented in the "Distributed Generation Interconnection Process" document. Both the technical requirements and process documents follow the State of Minnesota Distributed Generation Interconnection standards. These document requirements include, but are not limited to the following.

1. The member is responsible for reducing load from electrical service provided by the Association during control periods to be eligible for an interruptible rate.
2. The Association will make every effort to give the member one-half hour notice prior to the start of a control period, but it is not guaranteed. Notices will be given in the form of an email, text message, or load control signal.
3. The duration and frequency of control periods shall be at the discretion of the Association. Control periods will normally occur at such times when the Association expects peak load conditions or when, in the Association's opinion, the reliability of the system is endangered.
4. The member is obligated to remain on the Interruptible rate for a minimum period of one year.
5. For Schedule 71 only, field tests will be conducted during normal peak demand hours to determine the amount of controllable demand and thereby establish the initial coincidental demand level for billing purposes.
6. The minimum controllable demand to qualify for this service shall be 50 kW.
7. The Association shall not be liable for any loss or damage caused by or resulting from testing any other interruption of service.
8. The member must allow the Association to inspect and test the load control installation and equipment provided by the member.
9. The member must notify the Association of any modifications or changes that are made to the original load control installation and equipment provided by the member.

   The Association will supply a single dry contact to a member to initiate the load control. The member is responsible for any wiring from the Association provided dry contact to the member owned equipment. The member must provide and maintain a dial in direct (DID) telephone line to the Association's metering equipment. (PBX DID lines are acceptable.) The exact location of the phone line shall be verified with the Association. Alternatively, the member may select cellular meter and pay applicable communication fee.
10. Generator must be available for control at all times or the member will/may be removed from the rate, unless prior written approval is given by Dakota Electric.

MEMBER SERVICE INFORMATION
INTERRUPTIBLE SERVICE (SCHEDULES 70 AND 71)
(Continued)

B. General Rules and Policies for Distributed Generation Interconnection

1. The generation system installation must meet all of the applicable local and national standards for generation interconnection as well as the Dakota Electric Association Distributed Generation Interconnection Requirements. Any member that operates their generation system in non-compliance with these interconnection requirements will be subject to discontinuance of service. Current interconnection documents are available on the Association's Web site at http://light.dakotaelectric.com/Handbook/Pages1/Interconnecting Generation.aspx. The main topics covered in the Interconnection Requirements document include, but are not limited to:
    a. Types of Interconnection
    b. Interconnection Issues and Technical Requirements
    c. Generation Metering, Monitoring, and Control
    d. Protective Devices and Systems
    e. Agreements
    f. Metering Requirements

2. The member is responsible for all status point wiring from the on-site generation system to the Association's monitoring equipment. The generation status points typically include but are not limited to:
    a. Generator and Utility switch or breaker positions
    b. Generator Status – running or not running
    c. Generator Trouble Alarm Status
    d. Lock Out Relay Status – if applicable

3. The member retains responsibility for compliance with local and national standards in addition to the Dakota Electric Interconnection Requirements as they may change over time. No consumer may connect on-site generation in parallel with the Association's system without prior written consent of the Association.

4. The interconnection of member's facilities with the Association's system shall not interfere with the quality of the Association's service to any of its other members.

5. The member's operation of on-site generators, shall be restricted to control periods, periodic maintenance, equipment testing, severe weather conditions, and power supply outages only.

6. The generator fuel supply must be adequate for at least ten (10) hours of operation at full load. The Association recommends a fuel supply of at least 24 hours to cover normal daily loads.

7. The Association's operation of the member's generation or curtailment systems will normally be during control periods, but the Association reserves the right to further control on-site generators or curtailment systems as needed to promote efficient and reliable operation of the Association's system.

8. The member will provide the necessary equipment as approved by the Association to enable the member to operate the on-site generation in parallel with the Association's system as specified in Dakota Electric Association's Interconnection Requirements document.

9. The Association reserves the right to discontinue service if continued parallel operations by the member results in trouble on the Association's system, such as interruptions, ground faults, radio or telephone interference, surges, or objectionable frequency and voltage fluctuations, where such trouble is caused by a member, and the member fails to remedy the causes thereof within a reasonable time.

Docket No. E-111/GR-19-478

Exhibit__(DEA-16)
Residential Time of Use
Rate Analysis

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Residential Billing Determinants & COS Results

Residential Billing Determinants

100,235	Consumers
838,684	Energy Sales - All (MWh)
281,636	Energy Sales - On-Peak (MWh)
557,048	Energy Sales - Off-Peak (MWh)

Summary of Residential Revenue Requirements

	Power Supply
	Wholesale Power
10,370,341	Demand Related - Summer
5,458,423	Demand Related - Winter
4,952,367	Demand Related - Other
20,781,131	Subtotal - Demand
-	Energy Related - Critical Peak
17,333,391	Energy Related - On-Peak
26,723,916	Energy Related - Off-Peak
44,057,307	Subtotal Energy
	Revenue Related
64,838,438	Subtotal - Wholesale
	Allocated Overhead & Margin
-	Direct Related
-	Revenue Related
198,146	Demand Related
420,872	Energy Related
619,018	Subtotal - Allocated
65,457,456	Subtotal - Power Supply
	Transmission
-	Direct Assigned
13,696,762	Demand Related
-	Energy Related
13,696,762	Subtotal - Transmission
	Allocated Overhead & Margin
-	Direct Related
-	Revenue Related
-	Demand Related
-	Energy Related
-	Subtotal - Allocated
13,696,762	Subtotal - Transmission
	Distribution
3,010,588	Dist. Sub. - Capacity
-	Dist. Sub. - Consumer
6,733,215	Primary Line - Capacity
11,552,938	Primary Line - Consumer
369,821	Line Transf. - Capacity
1,946,450	Line Transf. - Consumer
165,079	Sec. & Serv.
5,150,000	Meter
11,393,185	Acct. & Serv.
-	Revenue Related
-	Direct Assigned
40,321,276	Subtotal - Distribution
3,608,460	Additional TOU Metering
123,083,954	**Total**

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Cost Assignment

Residential Distribution Revenue

	15,636,660	Fixed Charge Revenue
	28,912,094	Energy Revenue
	44,548,754	Distribution Total
$	0.03450	Distribution Revenue per kWh

	Transmission	*D-Summer*	*D-Winter*	*D-Spr/Fall*	*Energy - CP*	*E - On-Peak*	*E - Off-Peak*	*Total*
On-Peak Summer	4,080,601	9,506,146			-	2,722,337	1,231,580	17,540,664
On-Peak Winter	3,011,023		5,003,554			2,242,233	1,030,336	11,287,145
On-Peak Spr/Fall	5,463,742			4,539,670		4,080,950	1,906,150	15,990,512
Int Peak	1,141,397	864,195	454,869	412,697		8,287,871	3,686,195	14,847,224
Off-Peak							18,869,655	18,869,655
	13,696,762	10,370,341	5,458,423	4,952,367	-	17,333,391	26,723,916	78,535,200

	GRE On-Peak Energy	*GRE Off-Peak Energy*
On-Peak Summer	15.7%	4.6%
On-Peak Winter	12.9%	3.9%
On-Peak Spr/Fall	23.5%	7.1%
Int Peak	47.8%	13.8%
Off-Peak		70.6%
	100.0%	100.0%

Coincident Demand

Summer	608.3	32.5%
Winter	448.9	24.0%
Other	814.5	43.5%
	1871.8	100.0%

Dakota Electric Association
Residential TOU Rate (Schedule 56)
kWh Billing Unit Estimates

Test Year Forecast (2019)

Month	kWh	%		
1	753	9.0%		
2	623	7.4%	25.5%	25%
3	618	7.4%		
4	533	6.4%	21.0%	21%
5	604	7.2%		
6	765	9.1%		
7	975	11.7%	31.0%	31%
8	854	10.2%		
9	659	7.9%		
10	619	7.4%	22.6%	23%
11	610	7.3%		
12	756	9.0%		
	8,369	100.0%		

Rate 31 Energy Sales

Summer	257,025,312	30.7%	30%
Other	581,064,216	69.3%	70%
	838,089,528		

Hours

On-Peak (3 - 11)	23.8%	25%
Int Peak (7 - 3)	23.8%	25%
Off-Peak (11 - 7)	52.4%	50%
	100.0%	100%

Period Hours & kWh Billing Unit Estimates

On-Peak Summer	8.2%	68,882,180
On-Peak Winter	6.8%	57,053,538
On-Peak S/F	12.5%	104,468,100
Int Peak	24.9%	208,412,955
Off-Peak	47.6%	399,272,755
	100%	838,089,528

Dakota Electric Association
Residential TOU Rate (Schedule 56)
Rate Design

Rate Design

Fixed Charge	100,235	cons.	$	13.00	15,636,660
Energy Charge					
Peak Period					
Summer	68,882,180	kWh	$	0.289	19,916,935
Winter	57,053,538	kWh	$	0.232	13,255,357
Spring/Fall	104,468,100	kWh	$	0.188	19,594,413
Int. Period	208,412,955	kWh	$	0.106	22,036,975
Off-Peak Period	399,272,755	kWh	$	0.082	32,643,615
	838,089,528	kWh	Total		123,083,954

Definitions:
Summer = June, July, Aug
Winter = Dec, Jan, Feb
Spring/Fall = Mar. Apr, May, Sept, Oct, Nov
Peak Period = 3 pm to 11 pm M-F excl holidays
Intermediate Peak = 7 am to 3 pm M-F excl holidays
Off-Peak = all other hours

Docket No. E-111/GR-19-478

Exhibit__(DEA-15)
EV Rate Analysis

Dakota Electric Association
Residential Electric Vehicle Rate
Wholesale Power Costs

1. Assumptions

2.5% Distribution Line Loss

80% Coincidence Factor

Level 2 Charger

6.6	kW Demand
2.9	Hours to Full Charge
10.96	kWh Energy per Day

2. Wholesale Power Rates (GRE 2019)

Energy Charge			
Off Peak Energy Rate	@	$0.04646	/kWh
On Peak Energy Rate	@	$0.05939	/kWh
Critical Peak Energy Rate	@	$0.05939	/kWh
Capacity Charge			
Summer (Jun-Aug)	@	$18.24	/kW/mo.
Winter (Dec-Feb)	@	$12.16	/kW/mo.
Other	@	$6.08	/kW/mo.
Average		$10.64	
Transmission Charge	@	$6.57	/kW/mo.
Ancillary Charge	@	$0.69	/kW/mo.
	@	$0.00009	/kWh

3. Annual Energy

12,000	Annual Miles per Year
3.65	Average Miles per kWh
3,288	Annual Energy (kWh)

4. Peak Charging

Level 2:

Demand (charging from 4 pm to 9 pm):

6.6	kW Demand
80%	Coincidence Factor
5.28	Diversified Demand
$ 17.90	Average Monthly Coincident Charges per kW
$ 94.51	Subtotal
12	Months
$ 1,134.14	Subtotal
2.5%	Line Loss
$ 1,162.50	Annual Demand Cost

Summary of Cost of Service Analysis
Load Management Rates

I. Summary

(a) Rate Description	(b) GRE Rate (¢/kWh)	(c) Line Losses (¢/kWh)	(d) Meter & Control (¢/kWh)	(e) Allocated Distribution (¢/kWh)	(f) Margin (¢/kWh)	(g) Total Cost (¢/kWh)	(h) Weighted Sales (%)	(i) Retail Rate (¢/kWh)
Schedule EV-1								
Residential Electric Vehicle	4.655	0.116	0.420	2.130	0.236	7.56	100%	**7.56**

Col.	Notes
(b)	Based on GRE wholesale rate schedules for Year 2019, off peak energy rate plus ancillary service energy charge.
(c)	GRE General Service Energy Rate x 2.5% which represents the average losses for the system.
(d)	Average annual cost per kWh from load management analysis.
(e)	Allocated distribution cost from load management analysis.
(f)	Margin percent times sum of Col. (b) to Col. (e).
(g)	Sum Col. (b) to Col. (f).

Dakota Electric Association
Residential Electric Vehicle Rate
Rate Design

Line			
	Off-Peak		
1		$ 0.0756	Page 2 of 3
	On-Peak		
2		$ 0.0756	Off-Peak Energy Charge
3		$ 0.05939	Wholesale On-Peak Energy (see Page 1 of 3)
4	-	$ 0.04646	Wholesale Off-Peak Energy (see Page 1 of 3)
5	=	$ 0.01293	Additional Cost of On-Peak Wholesale Energy
6		$ 1,162.50	Annual Demand Cost (see Page 1 of 3)
7	÷	3,288	Annual Energy - kWh (see Page 1 of 3)
8	=	$ 0.35356	Demand Cost per kWh
9		$ 0.4421	Total On-Peak Rate (sum of lines 2, 5 and 8)

Present Billed Rates

	0.0674	Off-Peak Tariffed Rate
+	0.0025	RTA
=	0.0699	Off-Peak Billed Energy Charges
	0.4144	On-Peak Tariffed Rate
+	0.0025	RTA
=	0.4169	On-Peak Billed Energy Charges

Docket No. E-111/GR-19-478

Exhibit__(DEA-14)
Standby Rate Analysis

Standby Analysis
Cost of Service Summary

Line	Distribution Component		General Service		
1	**Availability**				
2	Meter - Consumer		$	449,082	
3	Acct & Serve - Consumer			993,491	
4	Subtotal			1,442,574	
5	/Customer Months			33,072	
6	Customer Cost ($/Cust/Mo)		**$**	**43.62**	
7					
8	**Primary Service Component**				
9	Substation-Capacity		$	1,598,656	
10	Primary Line - Capacity			3,575,413	
11	Primary Line - Consumer			463,412	
12	Subtotal		$	5,637,481	
13	/Billing Demand kW			1,449,303	
14	Primary Delivery Cost ($/kW/Mo)		**$**	**3.89**	
15					
16	**Secondary Service Component**				
17	Line Transformer Capacity		$	87,871	
18	Line Transformer Consumer			96,436	
19	Sec & Serv. - Consumer			5,512	
20	Subtotal		$	189,819	
21	/Billing Demand kW			1,449,303	
22	Secondary Delivery Cost($/kW/Mo)		**$**	**0.13**	
23	Total		**$**	**4.02**	
24					
25	**Substation Standby Reservation Fee**				
26	Total System Substation Capacity Cost		$	6,109,403	
27	Total Base Rated Substation Capacity	÷		632,500	kVA
28	Subtotal	=	$	9.66	
29	Months	÷		12	
30	Cost per kW-mo	=	**$**	**0.81**	

Docket No. E-111/GR-19-478

Exhibit__(DEA-13)
Air Conditioning Analysis

Dakota Electric Association
Cycled Air Conditioning Credit

Assume:	2.5	Tons AC Capacity
	14.0	Average SEER Rating
	65.0%	Average Peak Diversity Factor
	50.0%	Control Cycle

Cost Analysis (2019 GRE wholesale rates)

	$	18.24	Summer Capacity (per kW month)
+	$	6.57	Transmission (per kW month)
+	$	0.69	Ancillary Service (per kW month)
=	$	25.50	Subtotal
x		3	Summer Months
=	$	76.50	Capacity Savings per Coincident kW
x		0.70	Estimated Coincident Demand Reduction (kW)
=	$	53.28	Power Cost Capacity Savings
+	$	-	Estimated Critical Peak Energy Savings
+	$	15.00	GRE Credit ($5 per unit times 3 months)
=	$	68.28	Estimated Net Power Cost Savings (Summer Season)
-	$	23.38	Control Equipment and Program Costs
-	**$**	**39.00**	**Controlled Credits for Summer Season**
=	$	5.89	Net Annual Revenue

<u>Control Equipment and Program Costs:</u>

	$	116.00	Receiver
+	$	118.00	Electrician and Permit
+	$	17.00	Meter Technician
+	$	(100.00)	GRE Reimbursement
=	$	151.00	Net installed cost of control equipment
x		14.7%	Annualizing Factor *
=	$	22.18	Subtotal
+	$	1.20	Program marketing and Administration **
=	$	23.38	Control Equipment and Program Costs

* Annualizing factor includes interest, depreciation, and O&M.

** Program marketing and administration estimated at 0.1¢ per kWh times typical annual AC consumption of 1,200 kWh.

Docket No. E-111/GR-19-478

Exhibit__(DEA-12)
Base Calculation for Resource &
Tax Adjustment Components

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Energy Cost Adjustment (ECA)

Average Wholesale Energy Cost per kWh		$	0.0521
Rate 70 & 71 Energy Sales			406,800,000
Rate 36 Interruptible Energy Sales			7,801,344
Interruptible Wholesale Energy Cost	=	$	21,600,730
ECA Base per kWh Sold		**$**	**0.0521**

Load Management Rates

Rate 51			
GRE Wholesale Cost - ETS Water Heating		$	0.0200
Rate 51 - ETS Water Heating Sales	x		8,491,977
Rate 51 - ETS Water Heating Power Cost	=	$	169,840
GRE Wholesale Cost - ETS Space Heating		$	0.0225
Rate 51 - ETS Space Heating Sales	x		1,816,023
Rate 51 - ETS Space Heating Power Cost	=	$	40,861
GRE Wholesale Cost - ETS Electric Vehicle		$	0.0200
Rate 51 - ETS Electric Vehicle Sales	x		300,960
Rate 51 - ETS Electric Vehicle Power Cost	=	$	6,019
Rate 51 Power Costs		$	216,720
Rate 51 Energy Sales	÷		10,608,960
Rate 51 Weighted Power Cost Base per kWh Sold	=	**$**	**0.0204**
Rate 52			
GRE Wholesale Cost - Peak Shave Water Heating		$	0.0340
Rate 52 - Peak Shave Water Heating Sales	x		23,557,907
Rate 52 - Peak Shave Water Heating Power Cost	=	$	800,969
GRE Wholesale Cost - Dual Fuel Space Heating		$	0.0365
Rate 52 - Dual Fuel Space Heating Sales	x		20,569,693
Rate 52 - Dual Fuel Space Heating Power Cost	=	$	750,794
Rate 52 Power Costs		$	1,551,763
Rate 52 Energy Sales	÷		44,127,600
Rate 52 Weighted Power Cost Base per kWh Sold	=	**$**	**0.0352**

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Geothermal

Rate 49			
GRE Wholesale Cost - Geothermal		$	0.0813
Rate 49 - Geothermal Energy Sales	x		172,800
Rate 49 - Geothermal Power Cost	=	$	14,049
Rate 49 Power Cost Base per kWh Sold		**$**	**0.0813**

Power Cost Adjustment (PCA)

Total Wholesale Power Cost		$	150,649,466 [A]
ECA Power Cost	-		21,600,730
Rate 51 Power Cost	-		216,720
Rate 52 Power Cost	-		1,551,763
Rate 49 Power Cost	-		14,049
Wellspring (wholesale pass-through)	-		23,370
Member Specific Discount (wholesale pass-through)	-		(45,040)
Large Load High Load Factor Credit (wholesale pass-through)	-		-
Contract Rate Service (wholesale pass-through)	-		-
Standby (wholesale pass-through)	-		27,060
Firm Wholesale Power Cost	=		127,260,814
Firm kWh Energy Sales	÷		1,354,802,496
PCA Power Cost Base per kWh Sold	=	**$**	**0.0939**

Total Wholesale Power Cost		$	150,649,466
Total Energy Sales	÷		1,824,313,200 [B]
Total System Power Cost per kWh Sold	=	**$**	**0.0826**

Notes:

[A] See Exhibit__(DEA-1), page 22 of 22.

[B] See Exhibit__(DEA-1), page 12 of 22.

Dakota Electric Association
Base Calculation for Resource & Tax Adjustment Components

Conservation & DSM Spending Base Calculation

2019 Budget Conservation & DSM Spending	$	2,206,789 [C]
Test Year MWh Sales		1,824,313
Conservation & DSM Base per kWh	**$**	**0.0012**

Property Tax Recovery Base Calculation

Test Year Real & Personal Property Taxes	$	3,550,790 [D]
Test Year MWh Sales		1,824,313
Property & R/E Tax Recovery Base per kWh	**$**	**0.0019**

Allocation to Rate Classes Using Cost of Service Method		
Class & Rate	Property & Real Estate Taxes in Base Rates [E]	% of Taxes
Residential & Farm Service 31 Residential 32 Res'l Demand Control 53 Res'l Time of Day	$ 2,223,454	62.62%
Irrigation - 36	25,070	0.71%
Small General Service - 41	116,013	3.27%
General Service - 46 46 - General Service 49 - Geothermal 54 - General Service Time of Day	614,089	17.29%
Interruptible Service - 70 & 71	449,646	12.66%
Lighting - 44, 44-1, 44-2, 44-3	122,518	3.45%
TOTAL	**$ 3,550,790**	100.00%

Notes:

[C] See Workpaper #9

[D] Per Summary of Test Year Adjustments, Exhibit__(DEA_1) Page 2 of 22.

[E] Per Allocation of Revenue Requirements to Rate Classes, Exhibit__(DEA-3). Page 22 of 42.

Docket No. E-111/GR-19-478

Exhibit__(DEA-11)
Line Extension Analysis

Dakota Electric Association
Residential Line Extension Analysis

PROJECT	Direct Labor	Labor Overheads	Contract Labor	Materials, Tools, Supp	Undefined	Total before CIAC	Length (Feet)	Total Cost per Ft before CIAC	Present CIAC Charges	Proposed CIAC Method	Net DEA Cost Above Prop. Recovery Incl. Rates
118039	2,655.61	1,327.82	7,042.05	2,348.02	1,460.59	14,834.09	195	$ 76.07	$ 1,496	$ 3,145	$ 10,407
128798	429.36	214.70	0.00	124.87	236.15	1,005.08	-	NA	$ 500	$ 1,000	$ -
129137	4,054.75	2,487.39	2,062.30	6,594.29	2,230.10	17,428.83	620	$ 28.11	$ 5,024	$ 7,820	$ 8,327
129398	3,456.87	1,728.45	17,769.67	8,834.64	1,901.28	33,690.91	2,153	$ 15.65	$ 10,614	$ 24,683	$ 7,726
130963	1,534.41	767.21	1,512.15	2,378.05	843.93	7,035.75	275	$ 25.58	$ 2,160	$ 4,025	$ 1,729
131747	497.46	248.73	3,876.23	3,899.88	273.60	8,795.90	150	$ 58.64	$ 1,123	$ 2,650	$ 4,864
132939	3,832.37	1,916.21	2,636.92	2,104.75	2,107.81	12,598.06	90	$ 139.98	$ 625	$ 1,990	$ 9,326
133275	1,655.35	987.67	2,891.62	3,280.08	910.45	9,725.17	75	$ 129.67	$ 500	$ 1,825	$ 6,618
133908	2,276.56	1,130.80	2,008.81	2,963.36	1,252.12	9,631.65	442	$ 21.79	$ 3,546	$ 5,862	$ 2,488
134735	2,438.94	1,219.47	0.00	708.47	1,341.42	5,708.30	-	NA	$ 500	$ 1,000	$ 3,426
134795	2,039.50	987.71	9,635.73	4,706.63	1,121.72	18,491.29	209	$ 88.48	$ 1,612	$ 3,299	$ 13,910
134963	1,927.67	720.29	6,230.14	3,285.81	1,060.23	13,224.14	380	$ 34.80	$ 3,032	$ 5,180	$ 6,762
135498	957.98	235.45	1,364.93	2,068.57	526.89	5,153.82	140	$ 36.81	$ 1,040	$ 2,540	$ 1,332
135680	1,239.68	619.86	2,710.17	3,135.59	681.82	8,387.12	475	$ 17.66	$ 3,820	$ 6,225	$ 880
135885	2,207.10	1,103.55	0.00	1,480.77	1,213.91	6,005.33	-	NA	$ 500	$ 1,000	$ 3,723
135973	1,149.39	882.70	0.00	1,609.97	632.16	4,274.22	-	NA	$ 500	$ 1,000	$ 1,992
136252	1,298.65	704.33	1,815.17	2,981.63	714.26	7,514.04	300	$ 25.05	$ 2,368	$ 4,300	$ 1,932
137790	274.42	181.22	0.00	1,415.44	150.92	2,022.00	-	NA	$ 500	$ 1,000	$ -
138306	1,103.55	551.78	0.00	1,338.55	606.95	3,600.83	-	NA	$ 500	$ 1,000	$ 1,319
139509	767.70	383.85	0.00	282.01	422.24	1,855.80	-	NA	$ 213	$ 1,000	$ -
142657	1,454.27	727.17	0.00	1,642.55	799.86	4,623.85	-	NA	$ 500	$ 1,000	$ 2,342
	$ 37,252	$ 19,126	$ 61,556	$ 57,184	$ 20,488	$ 195,606	5,504	30.25	$ 40,670	$ 81,544	$ 89,103
							CIAC as percent of total cost			42%	
							Additional DEA Revenue			$ 40,874	

	$ 3,637	Avg Cost for Extensions with No Footage
-	$ 1,282	Allocated Dist. Plant - Residential [1]
=	$ 2,355	Cost Basis for Flat Fee
	$ 1,000	**Proposed Flat Fee**
	$ 12,809	Avg Cost for Extensions with more than zero feet
-	$ 1,282	Allocated Distribution Plant - Residential
-	$ 1,000	Proposed Flat Fee
=	$ 10,527	Cost Basis for per Foot Charge
	423	Average Footage
	$ 24.86	Per Foot Cost Basis
	$ 11.00	**Proposed per Foot Charge**

Notes:
1 Total residential allocated distribution plant before depreciation.

Class Line Extension Cost Analysis

Line	Description	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1							
2	**I. Class Load Data**						
3	Number of Customers	100,235	4,431	392	2,756	262	16,771
4	Energy (kWh)	838,683,744	42,537,600	7,963,872	463,059,984	406,800,000	10,358,640
5	Billing Demand (kW)	-	-	76,255	1,449,303	970,490	-
6	Base Revenue Per Cons. (Rev - PS)	$ 336	$ 383	$ 1,154	$ 2,584	$ 10,215	$ 76
7							
8	**II. Allocation of Plant**						
9	A. Distribution Extension Items						
10	Poles, towers	$ 11,800,477	$ 612,764	$ 103,966	$ 2,210,293	$ 1,519,012	$ 74,064
11	OH Cond	$ 15,474,059	$ 812,987	$ 106,739	$ 1,411,713	$ 732,940	$ 67,527
12	UG Conduit	$ -	$ -	$ -	$ -	$ -	$ -
13	UG Cond	$ 66,119,564	$ 3,366,400	$ 791,973	$ 22,906,645	$ 17,421,660	$ 624,437
16	Net Plant	$ 93,394,100	$ 4,792,151	$ 1,002,678	$ 26,528,652	$ 19,673,611	$ 766,027
17							
18	Average Plant Invest. / Customer	$ 931.75	$ 1,081.51	$ 2,557.85	$ 9,625.78	$ 75,090.12	$ 45.68
19	Average Plant Invest. / kWh	$ 0.11136	$ 0.11266	$ 0.12590	$ 0.05729	$ 0.04836	$ 0.07395
20	Average Plant Invest. / kW	n/a	n/a	$ 13.15	$ 18.30	$ 20.27	n/a
21	Multiple of Base Revenue	2.8	2.8	2.2	3.7	7.4	0.6
22							
23	B. Service Extension Items						
24	Transf	$ 29,061,904	$ 1,661,843	$ 310,808	$ 2,312,468	$ 761,492	$ 98,727
25	Services	$ 2,401,440	$ 115,874	$ 11,602	$ 80,186	$ 7,918	$ 8,036
26	Meters	$ 3,602,323	$ 218,184	$ 40,621	$ 314,124	$ 138,790	$ 12,055
27	Cons Premise	$ -	$ -	$ -	$ -	$ -	$ 123,745
28	Leased Prop	$ -	$ -	$ -	$ -	$ -	$ -
29	St. Light	$ -	$ -	$ -	$ -	$ -	$ 9,800,721
32	Net Plant	$ 35,065,667	$ 1,995,901	$ 363,031	$ 2,706,778	$ 908,201	##########
33							
34	Average Plant Invest. / Customer	$ 349.83	$ 450.44	$ 926.10	$ 982.14	$ 3,466.41	$ 598.85
35	Average Plant Invest. / kWh	$ 0.04181	$ 0.04692	$ 0.04558	$ 0.00585	$ 0.00223	$ 0.96956
36	Average Plant Invest. / kW	n/a	n/a	$ 4.76	$ 1.87	$ 0.94	n/a
37	Multiple of Base Revenue	1.0	1.2	0.8	0.4	0.3	7.9
38							
39	C. Total Extension Items	$ 1,282	$ 1,532	$ 3,484	$ 10,608	$ 78,557	$ 645

Docket No. E-111/GR-19-478

Exhibit__(DEA-10)
Special Fees and Charges

Dakota Electric Association
Special Fees and Charges
Proposed Fee Changes

	Current Charge	Current Actual Cost	**Proposed Charge**	2018 Frequency	Add'l Revenue
Meter test at customer's request					
Single phase	$ 85.00	$ 98.40	**$ 95.00**	-	$ -
Three phase	$ 100.00	$ 116.34	**$ 110.00**	-	-
Bad check	$ 15.00	$ 11.47	**$ 11.50**	2,259	(7,907)
Reconnection charge (after disconnect, same customer)					
Self contained meter					
Normal working hours	$ 50.00	$ 57.52	**$ 55.00**	741	3,705
After hours	$ 130.00	$ 148.09	**$ 145.00**	28	420
Transformer rated meter					
Normal working hours	$ 175.00	$ 189.77	**$ 185.00**	14	140
After hours	$ 315.00	$ 349.15	**$ 340.00**	1	25
Service charge (outside normal working hours when problem is not with DEA equipment)	$ 280.00	$ 349.15	**$ 340.00**	1	60
Load Management Service Charge					
Normal working hours	$ 70.00	$ 80.46	**$ 80.00**		-
After hours	$ 140.00	$ 161.47	**$ 160.00**	1	20
Pulse meter	$ 500.00	$ 752.26	**$ 750.00**	-	-
Temporary service					
Non-winter months	$ 205.00	N/A	**$ -**	8	(1,640)
Winter months	$ 340.00	N/A	**$ -**	5	(1,700)
Transfer/connection	$ 17.50	$ 19.15	**$ 17.50**	18,760	-
					$ (6,877)

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges

Meter Test at Customer's Request

Single Phase Meter

Task	Item	Job Title			Hourly Rate		Hours	Overhead		Total
Changing Meter:	Labor	Meter Technician			**44.57**		1.00	61.0%	$	71.76
Testing Meter:	Labor	Meter Technician			**44.57**		0.25	61.0%	$	17.94
	Mileage		15		miles	$	**0.58**	Rate	$	8.70
								Total	$	98.40

Three Phase Meter

Task	Item	Job Title			Hourly Rate		Hours	Overhead		Total
Changing Meter:	Labor	Meter Technician			44.57		1.00	61.0%	$	71.76
Testing Meter:	Labor	Meter Technician			44.57		0.50	61.0%	$	35.88
	Mileage		15		miles	$	0.58	Rate	$	8.70
								Total	$	116.34

Bad Check or NSF Check

Task	Item	Job Title		Hourly Rate	Minutes	Overhead		Total
Research, Correspondence & Data entry	Labor	Consumer Payment Rep	**$**	**26.80**	5	61.0%	$	3.60
	Bank service charge						**$**	**7.25**
	Correspondence expenses						**$**	**0.62**
						Total	$	11.47

Reconnect Charge

Self Contained Meter - One Person, one vehicle

Task	Item	Job Title			Hourly Rate		Hours	Overhead		Total
Working hours	Labor	Credit Field Rep		**$**	**40.43**		0.75	61.0%	$	48.82
	Mileage		15		miles	$	0.58	Rate	$	8.70
								Total	$	57.52

Task	Item	Job Title			Overtime rate @ 1.5x		Hours	Payroll Taxes Only		Total
After hours	Labor	Meter Technician		$	60.65		2.00	7.74%	$	130.69
	Mileage		30		miles	$	0.58	Rate	$	17.40
								Total	$	148.09

Transformer Rated Meter - Two person crew, one truck

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Working hours	Labor	Crew Chief	**$**	**51.70**	1.00	61.0%	$	83.24
	Labor	Power Line Specialist	**$**	**46.55**	1.00	61.0%	$	74.95
	Bucket Truck		**$**	**31.58**	1.00		$	31.58
						Total	$	189.77

Task	Item	Job Title		Overtime rate @ 1.5x	Hours	Payroll Taxes Only		Total
After hours	Labor	Crew Chief	$	77.55	2.00	7.74%	$	167.10
	Labor	Power Line Specialist	$	69.83	2.00	7.74%	$	150.47
	Bucket Truck		$	31.58	1.00		$	31.58
						Total	$	349.15

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges
(Continued)

Service Charge - two person crew, one truck
(service trouble calls after working hours, when the problem is not with DEA's equipment)

Task	Item	Job Title		Overtime rate @ 1.5x	Hours	Payroll Taxes Only		Total
After hours	Labor	Crew Chief	$	77.55	2.00	7.74%	$	167.10
	Labor	Power Line Specialist	$	69.83	2.00	7.74%	$	150.47
	Bucket Truck		$	31.58	1.00		$	31.58
						Total	$	349.15

Load Management Service Charge

Task	Item	Job Title						Total
Working Hours								
Testing	Labor	Meter Technician		44.57	1.00	61.0%	$	71.76
	Mileage		15	miles	$ 0.58	Rate	$	8.70
						Total	$	80.46
After hours	Labor	Meter Technician	$	66.86	2.00	7.74%	$	144.07
	Mileage		30	miles	$ 0.58	Rate	$	17.40
						Total	$	161.47

Pulse Meter (materials and installation)

Task	Item	Job Title		Hourly Rate	Hours	Overhead		Total
Installation	Labor	Meter Technician	$	44.57	2.00	61.0%	$	143.52
	Labor	Meter Technician	$	44.57	2.00	61.0%	$	143.52
	Equipment	Meter					**$**	**285.00**
	Equipment	KYZ pulse board					**$**	**70.00**
	Labor	install & test board	$	44.57	0.75	61.0%	$	53.82
	Equipment	test switch					**$**	**170.22**
	Equipment	Miscellaneous equipment					**$**	**10.00**
						Total	$	752.26

Dakota Electric Association
Cost Justification for Proposed Special Fees and Charges
(Continued)

Transfer/Connection Charge Analysis

Task	Employees	Job Title		Hourly Rate	(% of 2080) Hours	Overhead		Total
Inside Clerical								
Telephone & resolution	12	Member Service Reps	$	26.80	8.8%	61.0%	$	94,773.72
Supervision	2	MSR Leads	**$**	**31.20**	1.5%	61.0%	$	3,134.48
Outside Field Personnel								
	1	Transfer representative	**$**	**36.47**	70%	61.0%	$	85,491.52
	1	Chief meter reader	$	36.47	39%	61.0%	$	47,630.99
	1	Meter reader	$	36.47	65%	61.0%	$	79,384.98
Vehicle Expense	Mileage	Transfer representative		**25,400**	70.00%	17,780		
		Chief meter reader		**17,700**	39.00%	6,903		
		Meter reader		**16,600**	65.00%	10,790		
					Subtotal	35,473		
		Mileage Rate	$	0.58			$	20,574.34
Data Processing								
Itineris Support		Monthly Support	**$**	**18,180.00**	10.00%		$	21,816.00
PC & 2 monitors	12	Annual cost	**$**	**430.00**	8.80%		$	454.00
			Number					
Mailing	Kubra cost per item including postage				**$ 0.63**			
			Subtotal		$ 0.63	**9,380**	$	5,909.40

Total	$	359,169.43
Transfers		18,760
$/Transfer	$	19.15

Dakota Electric Association
Special Fees and Charges
Frequency Analysis

	2013	2018
Meter test at customer's request		
Single phase	4	-
Three phase	-	
Bad check	1,476	2,259
Reconnection charge (after disconnect, same customer)		
Self contained meter		
Normal working hours	1,241	741
After hours	131	28
Transformer rated meter		
Normal working hours	6	14
After hours	2	1
Service charge	1	1
(outside normal working hours		
when problem is not with DEA equipment)		
Pulse meter	-	
Temporary service	34	13
Transfer/connection	13,722	18,760

Dakota Electric Association
Special Fees and Charges
Payroll Overhead Calculation

	Future Test Year	
Pension	16.71%	[1]
Savings (401k)	6.77%	[1]
FICA Tax [2]	7.60%	[1]
Life Insurance	0.60%	[1]
Workers' Compensation	1.32%	[1]
Medical Insurance	12.87%	[1]
State & Federal Unemployment	0.14%	[1]
Other-Retirement Health Benefits	0.93%	[1]
Benefits excluding time-off	46.94%	
Vacation/Sick/Holiday (assumed 269 hrs)	14.04%	
Total overhead allocation	60.98%	
Payroll taxes only	7.74%	

[1] See Exhibit__(DEA-1), page 6 of 20.

Docket No. E-111/GR-19-478

Exhibit__(DEA-9)
Summary of Lead-Lag Study

Dakota Electric Association
Summary of Lead Lag Analysis
Cash Working Capital Analysis
Twelve Months Ending December 31, 2018

Description	Test Year Expense	365 Average Daily Expense	Expense Lag	Revenue Lag		Net Lag/ (Lead)	Working Capital Required/ (Provided)
Purchased Power	$ 149,356,821	$ 409,197	51.7	55.1		3.4	$ 1,399,996
Payroll (A)	15,112,543	41,404	11.0	55.1		44.1	1,826,799
Employee Benefits	6,003,178	16,447	(37.5)	55.1		92.6	1,523,343
Other O&M	9,484,952	25,986	18.3	55.1		36.8	956,839
Prepaid Insurance	570,291	1,562	(180.6)	55.1		235.7	368,197
Employer FICA/Medicare	1,334,808	3,657	14.4	55.1		40.7	148,918
Federal & State Unemployment Tax	26,186	72	60.0	55.1		(4.9)	(351)
Property Taxes	3,432,442	9,404	(30.5)	55.1		85.6	805,183
Total Expenses	$ 185,321,221						$ 7,028,924
Sales Tax	$ 11,767,404	32,239	34.9	28.3	(B)	(6.6)	$ (212,777)
Working Capital Required/ (Provided)							$ 6,816,147

(A) Operating payroll is estimated to be 86% of total payroll
(B) Revenue Collection or Customer Payment Lag

Docket No. E-111/GR-19-478

Exhibit__(DEA-8)
Coincidental Demand Charges

Dakota Electric Association
Calculation of Coincidental Demand Charges

C&I Interruptible (Rates 70 and 71)

1. Summer (June, July, August)

$	25.50	GRE Summer $/kW-mo.
+	2.50%	DEA Line Loss
	$26.14	Coincidental Demand Charge

2. Winter (January, February, December)

$	19.42	GRE Winter $/kW-mo.
+	2.50%	DEA Line Loss
	$19.91	Coincidental Demand Charge

3. Other Months

$	13.34	GRE Winter $/kW-mo.
+	2.50%	DEA Line Loss
	$13.67	Coincidental Demand Charge

Note: GRE wholesale rates include capacity, transmission, and ancillary service charges.

Docket No. E-111/GR-19-478

Exhibit__(DEA-7)
Monthly Fixed Charge Analysis

Monthly Fixed Charge Analysis
Residential Service (Schedule 31)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 1.89		
Interest	$ 0.63		
O&M	$ 3.49		
A&G	$ 1.68		
Subtotal		$ 7.70	
Transformer			
Depreciation	$ 0.68		
Interest	$ 0.23		
O&M	$ 0.03		
A&G	$ 0.01		
Subtotal		$ 0.96	$ 0.96
Meter & Service			
Depreciation	$ 0.18		
Interest	$ 0.06		
O&M	$ 2.66		
A&G	$ 1.28		
Subtotal		$ 4.19	$ 4.19
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 9.34		$ 9.34
Taxes & Miscellaneous	$ 1.21		$ 0.15
Margins	$ 1.72		$ 0.38
Subtotal		$ 12.27	
Total		$ 25.11	$ 15.01

Monthly Fixed Charge Analysis
Small General Service (Schedule 41)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 2.26		
Interest	$ 0.76		
O&M	$ 4.17		
A&G	$ 2.01		
Subtotal		$ 9.21	
Transformer			
Depreciation	$ 0.92		
Interest	$ 0.31		
O&M	$ 0.04		
A&G	$ 0.02		
Subtotal		$ 1.28	$ 1.28
Meter & Service			
Depreciation	$ 0.23		
Interest	$ 0.08		
O&M	$ 3.64		
A&G	$ 1.76		
Subtotal		$ 5.71	$ 5.71
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 12.79		$ 12.79
Taxes & Miscellaneous	$ 1.52		$ 0.15
Margins	$ 2.13		$ 0.38
Subtotal		$ 16.44	
Total		$ 32.65	$ 20.32

Monthly Fixed Charge Analysis
Irrigation Service (Schedule 36)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 2.85		
Interest	$ 0.95		
O&M	$ 5.25		
A&G	$ 2.53		
Subtotal		$ 11.58	
Transformer			
Depreciation	$ 1.29		
Interest	$ 0.43		
O&M	$ 0.06		
A&G	$ 0.02		
Subtotal		$ 1.80	$ 1.80
Meter & Service			
Depreciation	$ 0.43		
Interest	$ 0.14		
O&M	$ 7.67		
A&G	$ 3.70		
Subtotal		$ 11.94	$ 11.94
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 26.92		$ 26.92
Taxes & Miscellaneous	$ 2.22		$ 0.15
Margins	$ 2.85		$ 0.38
Subtotal		$ 31.99	
Total		$ 57.31	$ 41.19

Monthly Fixed Charge Analysis
General Service (Schedule 46)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	**$/cons./mo.**	**Excluding Primary Line $/cons./mo.**
Primary Line			
Depreciation	$ 2.76		
Interest	$ 0.93		
O&M	$ 5.09		
A&G	$ 2.46		
Subtotal		$ 11.24	
Transformer			
Depreciation	$ 1.23		
Interest	$ 0.41		
O&M	$ 0.05		
A&G	$ 0.02		
Subtotal		$ 1.72	$ 1.72
Meter & Service			
Depreciation	$ 0.46		
Interest	$ 0.15		
O&M	$ 8.44		
A&G	$ 4.07		
Subtotal		$ 13.12	$ 13.12
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 29.61		$ 29.61
Taxes & Miscellaneous	$ 2.23		$ 0.15
Margins	$ 2.78		$ 0.38
Subtotal		$ 34.63	
Total		$ 60.71	$ 44.99

Monthly Fixed Charge Analysis
C&I Interruptible Service (Schedules 70 & 71)

DEA

Customer Related Cost

Cost of Service Breakdown

	$/cons./mo.	$/cons./mo.	Excluding Primary Line $/cons./mo.
Primary Line			
Depreciation	$ 2.95		
Interest	$ 0.99		
O&M	$ 5.44		
A&G	$ 2.63		
Subtotal		$ 12.01	
Transformer			
Depreciation	$ 1.35		
Interest	$ 0.45		
O&M	$ 0.06		
A&G	$ 0.02		
Subtotal		$ 1.89	$ 1.89
Meter & Service			
Depreciation	$ 1.88		
Interest	$ 0.63		
O&M	$ 39.21		
A&G	$ 18.91		
Subtotal		$ 60.63	$ 60.63
Direct Investment			
Depreciation	$ -		
Interest	$ -		
O&M	$ -		
A&G	$ -		
Subtotal		$ -	$ -
Customer Accounting Expense	$ 137.64		$ 137.64
Taxes & Miscellaneous	$ 5.04		$ 0.15
Margins	$ 3.86		$ 0.38
Subtotal		$ 146.54	
Total		$ 221.08	$ 200.69

Docket No. E-111/GR-19-478

Exhibit__(DEA-6)
Comparison of Present and Proposed Rates

Comparison of
Present and Proposed Rate Schedules

Present Rates				Proposed Rates			
Residential & Farm Service (31)				**Residential & Farm Service (31)**			
Fixed Charge	@	$9.00	/month	Fixed Charge	@	$10.00	/month
Energy Charge				Energy Charge			
Summer	@	$0.13080	/kWh	Summer	@	$0.13790	/kWh
Other	@	$0.11680	/kWh	Other	@	$0.12390	/kWh
Residential & Farm Demand Control (32)				**Residential & Farm Demand Control (32)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Demand Charge				Demand Charge			
Summer	@	$14.70	/kW	Summer	@	$15.50	/kW
Other	@	$11.10	/kW	Other	@	$11.90	/kW
Energy Charge	@	$0.07600	/kWh	Energy Charge	@	$0.08100	/kWh
Electric Vehicle (33)				**Electric Vehicle (33)**			
Energy Charge				Energy Charge			
Off Peak	@	$0.06740	/kWh	Off Peak	@	$0.07560	/kWh
On Peak	@	$0.41440	/kWh	On Peak	@	$0.44210	/kWh
Other				Other			
Summer	@	$0.13080	/kWh	Summer	@	$0.13790	/kWh
Other	@	$0.11680	/kWh	Other	@	$0.12390	/kWh
Irrigation Service (36)				**Irrigation Service (36)**			
Firm Service				***Firm Service***			
Fixed Charge	@	$30.00	/month	Fixed Charge	@	$30.00	/month
Demand Charge				Demand Charge			/kW/mo.
Summer	@	$26.35	/kW/mo.	Summer	@	$26.60	/kW/mo.
Winter	@	$20.95	/kW/mo.	Winter	@	$21.20	
Other	@	$15.50	/kW/mo.	Other	@	$15.67	/kW/mo.
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Interruptible Service				***Interruptible Service***			
Fixed Charge	@	$30.00	/month	Fixed Charge	@	$30.00	/month
Demand Charge	@	$4.55	/kW/mo.	Demand Charge	@	$4.55	/kW/mo.
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Small General Service (41)				**Small General Service (41)**			
Fixed Charge	@	$14.00	/month	Fixed Charge	@	$15.00	/month
Energy Charge				Energy Charge			
Summer	@	$0.12690	/kWh	Summer	@	$0.13750	/kWh
Other	@	$0.11290	/kWh	Other	@	$0.12350	/kWh

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Security Lighting Service (44) - Closed to New				**Security Lighting Service (44) - Closed to New**			
175 W MV	@	N/A	/month	175 W MV	@	N/A	/month
100 W HPS	@	$10.10	/month	100 W HPS	@	$12.01	/month
150 W HPS	@	$11.99	/month	150 W HPS	@	$14.26	/month
250 W HPS	@	$15.79	/month	250 W HPS	@	$18.83	/month
Street Lighting System (44-1)				**Street Lighting System (44-1)**			
175 W MV (Clsd to New)	@	$10.52	/month	175 W MV (Clsd to New)	@	$13.25	/month
250 W MV (Clsd to New)	@	$13.46	/month	250 W MV (Clsd to New)	@	$16.74	/month
400 W MV (Clsd to New)	@	$18.54	/month	400 W MV (Clsd to New)	@	$22.71	/month
100 W HPS (Clse to New)	@	$7.56	/month	100 W HPS (Clse to New)	@	$9.61	/month
150 W HPS	@	$9.46	/month	150 W HPS	@	$11.78	/month
200 W HPS	@	$11.41	/month	200 W HPS	@	$14.18	/month
250 W HPS	@	$13.25	/month	250 W HPS	@	$16.35	/month
400 W HPS	@	$17.67	/month	400 W HPS	@	$21.24	/month
Street Lighting Service (44-2)				**Street Lighting Service (44-2)**			
175 W MV (Clsd to New)	@	$15.23	/month	175 W MV (Clsd to New)	@	$17.44	/month
250 W MV (Clsd to New)	@	$18.16	/month	250 W MV (Clsd to New)	@	$20.93	/month
400 W MV (Clsd to New)	@	$23.25	/month	400 W MV (Clsd to New)	@	$26.89	/month
100 W HPS (Clsd to New)	@	$12.27	/month	100 W HPS (Clsd to New)	@	$13.80	/month
150 W HPS (Clsd to New)	@	$14.16	/month	150 W HPS (Clsd to New)	@	$15.97	/month
250 W HPS (Clsd to New)	@	$17.95	/month	250 W HPS (Clsd to New)	@	$20.54	/month
400 W HPS (Clsd to New)	@	$22.38	/month	400 W HPS (Clsd to New)	@	$25.42	/month
Custom Residential Street Lighting (44-3)				**Custom Residential Street Lighting (44-3)**			
175 W MV (Clsd to New)	@	$11.37	/month	175 W MV (Clsd to New)	@	$14.03	/month
50 W HPS (Clsd to New)	@	$6.70	/month	50 W HPS (Clsd to New)	@	$8.45	/month
100 W HPS	@	$8.41	/month	100 W HPS	@	$10.39	/month
150 W HPS (Clsd to New)	@	$10.30	/month	150 W HPS (Clsd to New)	@	$12.63	/month
250 W HPS (Clsd to New)	@	$14.09	/month	250 W HPS (Clsd to New)	@	$17.21	/month
LED Security Lighting Service (44 -4)				**LED Security Lighting Service (44 -4)**			
LED, >4,500 Lumens	@	7.63	/month	LED, >4,500 Lumens	@	$7.75	/month

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
LED Street Lighting Member Owned(44-5)				**LED Street Lighting Member Owned(44-5)**			
A (40-80 watts)	@	4.81	/month	A (40-80 watts)	@	$5.50	/month
B (81-150 watts)	@	$6.71	/month	B (81-150 watts)	@	$7.75	/month
C (151-250 watts)	@	$9.66	/month	C (151-250 watts)	@	$11.16	/month
D (251-350 watts)	@	$13.05	/month	D (251-350 watts)	@	$15.04	/month
E (351-450 watts)	@	$16.52	/month	E (351-450 watts)		$19.07	/month
LED Street Lighting (44-6)				**LED Street Lighting (44-6)**			
Standard							
>5,200 L, Coach (Post)	@	$10.60	/month	>5,200 L, Coach (Post)	@	$9.30	/month
>5,200 L, Acorn (Post)	@	$11.24	/month	>5,200 L, Acorn (Post)	@	$10.85	/month
>7,000 L, Cobra (Mast)	@	$8.31	/month	>7,000 L, Cobra (Mast)	@	$8.60	/month
>11,500 L, Shoebox	@	$10.71	/month	>11,500 L, Shoebox	@	$10.70	/month
Basic							
>5,200 L, Coach (Post)	@	$6.83	/month	>5,200 L, Coach (Post)	@	$6.36	/month
>5,200 L, Acorn (Post)	@	$6.30	/month	>5,200 L, Acorn (Post)	@	$6.12	/month
>7,000 L, Cobra (Mast)	@	$6.51	/month	>7,000 L, Cobra (Mast)	@	$6.98	/month
>11,500 L, Shoebox	@	$7.98	/month	>11,500 L, Shoebox	@	$8.68	/month
Low Wattage Unmetered Service (45)				**Low Wattage Unmetered Service (45)**			
Fixed Charge	@	$10.00	/month	Fixed Charge	@	$10.50	/month
General Service (46)				**General Service (46)**			
Fixed Charge	@	$34.00	/month	Fixed Charge	@	$34.00	/month
Demand Charge				Demand Charge			
Summer	@	$12.26	/kW	Summer	@	$13.70	/kW
Other	@	$9.16	/kW	Other	@	$10.60	/kW
Energy Charge				Energy Charge			
First 200 kWh/kW	@	$0.07760	/kWh	First 200 kWh/kW	@	$0.07760	/kWh
Next 200 kWh/kW	@	$0.06760	/kWh	Next 200 kWh/kW	@	$0.06760	/kWh
Over 400 kWh/kW	@	$0.05760	/kWh	Over 400 kWh/kW	@	$0.05760	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Municipal Civil Defense Sirens (47)				**Municipal Civil Defense Sirens (47)**			
Fixed Charge	@	$5.00	/month	Fixed Charge	@	$5.00	/month
Geothermal Heat Pump (49) Closed to New				**Geothermal Heat Pump (49) Closed to New**			
Energy Charge	@	$0.09400	/kWh	Energy Charge	@	$0.10300	/kWh
Controlled Energy Storage (51)				**Controlled Energy Storage (51)**			
Net Energy Charge	@	$0.04400	/kWh	Net Energy Charge	@	$0.04870	/kWh
Controlled Interruptible Service (52)				**Controlled Interruptible Service (52)**			
Net Energy Charge	@	$0.05500	/kWh	Net Energy Charge	@	$0.06310	/kWh
Alternate Rate for Water				Alternate Rate for Water			
Heaters		($6.00)	/month	Heaters		($6.00)	/month
Residential & Farm Time of Day (53)				**Residential & Farm Time of Day (53)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Energy Charge				Energy Charge			
Peak Period				Peak Period			
Summer	@	$0.18800	/kWh	Summer	@	$0.21263	/kWh
Other	@	$0.17400	/kWh	Other	@	$0.19863	/kWh
Off-Peak	@	$0.09400	/kWh	Off-Peak	@	$0.09450	/kWh
General Service Time of Day (54)				**General Service Time of Day (54)**			
Fixed Charge	@	$36.00	/month	Fixed Charge	@	$36.00	/month
Demand Charge				Demand Charge			
Peak Period				Peak Period			
Summer	@	$24.85	/kW/mo.	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW/mo.	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW/mo.	Other	@	$13.67	/kW/mo.
Maximum	@	$4.75	/kW	Maximum	@	$5.25	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				Proposed Rates			
Residential & Farm Service Time of Day (56)				**Residential & Farm Service Time of Day (56)**			
Fixed Charge	@	$12.00	/month	Fixed Charge	@	$13.00	/month
Energy Charges				Energy Charges			
Peak Period				Peak Period			
Summer	@	$0.2710	/kWh	Summer	@	$0.2890	/kW/mo.
Winter	@	$0.2210	/kWh	Winter	@	$0.2320	/kW/mo.
Other	@	$0.1750	/kWh	Other	@	$0.1880	/kW/mo.
Intermediate Period	@	$0.0970	/kWh	Intermediate Period	@	$0.1060	/kWh
Off-Peak Period	@	$0.0760	/kWh	Off-Peak Period	@	$0.0820	/kWh
Standby Service (60)				**Standby Service (60)**			
Generation Reservation Fee				Generation Reservation Fee			
Summer	@	$3.21	/kW	Summer	@	$3.21	/kW
Winter	@	$2.47	/kW	Winter	@	$2.47	/kW
Other	@	$1.74	/kW	Other	@	$1.74	/kW
Distribution Reservation Fee				Distribution Reservation Fee			
Primary	@	$3.28	/kW	Primary	@	$3.89	/kW
Secondary	@	$3.51	/kW	Secondary	@	$4.02	/kW
Substation	@	$0.90	/kW	Substation	@	$0.81	/kW
Full Interruptible Service (70)				**Full Interruptible Service (70)**			
Fixed Charge	@	$110.00	/month	Fixed Charge	@	$130.00	/month
Communication Fee	@	$8.70	/month	Communication Fee	@	$8.70	/month
Coinc. Demand Charge				Coinc. Demand Charge			
Summer	@	$24.85	/kW	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW	Other	@	$13.67	/kW/mo.
Non-Coinc. Demand	@	$4.75	/kW	Non-Coinc. Demand	@	$5.25	/kW
Failure to Control		$5.00	/kW	Failure to Control	@	$5.00	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	
Partial Interruptible Service (71)				**Partial Interruptible Service (71)**			
Fixed Charge	@	$110.00	/month	Fixed Charge	@	$130.00	/month
Communication Fee	@	$8.70	/month	Communication Fee	@	$8.70	/month
Coinc. Demand Charge				Coinc. Demand Charge			
Summer	@	$24.85	/kW	Summer	@	$26.14	/kW/mo.
Winter	@	$18.95	/kW	Winter	@	$19.91	/kW/mo.
Other	@	$13.00	/kW	Other	@	$13.67	/kW/mo.
Non-Coinc. Demand	@	$4.75	/kW	Non-Coinc. Demand	@	$5.25	/kW
Excess Demand	@	$5.00	/kW	Excess Demand	@	$5.00	/kW
Energy Charge	@	$0.04990	/kWh	Energy Charge	@	$0.05210	/kWh
Primary Voltage Disc.	@	$0.15	/kW	Primary Voltage Disc.	@	$0.15	/kW
Primary Metering Disc.	@	2.00%		Primary Metering Disc.	@	2.00%	

Comparison of
Present and Proposed Rate Schedules
(Continued)

Present Rates				**Proposed Rates**			
Cycled Air Conditioning Service (80)				**Cycled Air Conditioning Service (80)**			
Option 1	@		/kWh	Option 1	@		/kWh
Option 2	@	($0.03200)	/kWh	Option 2	@	($0.03200)	/kWh
Option 3	@	($13.00)	/month	Option 3	@	($13.00)	/month
Option 4	@	($6.50)	/ton/mo.	Option 4	@	($6.50)	/ton/mo.

Comparison of Revenue
Present and Proposed Rates

(a)	(b)	(c)	(d)	(e)	(f)
		Revenue	**Revenue**	**Increase (Decrease)**	
Line No.	**Rate Class**	**Present Rates**	**Proposed Rates**	**Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44) - Closed to New	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44 -4)	31,109	31,434	325	1.04
12	LED Street Lighting Member Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49) Closed to New	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	1	(0.00)
26	Wellspring	23,370	23,370	-	-
27	**Total**	200,480,307	209,128,484	8,648,177	4.31

Comparison of Present and Proposed
Residential & Farm Service (31)

Present			**Proposed**		
Service Charge	$9.00	/mo.	Fixed Charge	$10.00	/mo.
Energy Charge			Energy Charge		
Summer	$0.13080	kWh	Summer	$0.13790	kWh
Other	$0.11680	kWh	Other	$0.12390	kWh
RTA Charge	$0.00250	kWh			

					Present vs. Proposed				Average Rate			
kWh/	Present		Proposed Billing		Summer		Other		Present		Proposed	
Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
100	22.33	20.93	23.79	22.39	1.46	6.54	1.46	6.98	22.33	20.93	23.79	22.39
200	35.66	32.86	37.58	34.78	1.92	5.38	1.92	5.84	17.83	16.43	18.79	17.39
300	48.99	44.79	51.37	47.17	2.38	4.86	2.38	5.31	16.33	14.93	17.12	15.72
400	62.32	56.72	65.16	59.56	2.84	4.56	2.84	5.01	15.58	14.18	16.29	14.89
500	75.65	68.65	78.95	71.95	3.30	4.36	3.30	4.81	15.13	13.73	15.79	14.39
600	88.98	80.58	92.74	84.34	3.76	4.23	3.76	4.67	14.83	13.43	15.46	14.06
700	102.31	92.51	106.53	96.73	4.22	4.12	4.22	4.56	14.62	13.22	15.22	13.82
800	115.64	104.44	120.32	109.12	4.68	4.05	4.68	4.48	14.46	13.06	15.04	13.64
900	128.97	116.37	134.11	121.51	5.14	3.99	5.14	4.42	14.33	12.93	14.90	13.50
1,000	142.30	128.30	147.90	133.90	5.60	3.94	5.60	4.36	14.23	12.83	14.79	13.39
1,100	155.63	140.23	161.69	146.29	6.06	3.89	6.06	4.32	14.15	12.75	14.70	13.30
1,200	168.96	152.16	175.48	158.68	6.52	3.86	6.52	4.28	14.08	12.68	14.62	13.22
1,300	182.29	164.09	189.27	171.07	6.98	3.83	6.98	4.25	14.02	12.62	14.56	13.16
1,400	195.62	176.02	203.06	183.46	7.44	3.80	7.44	4.23	13.97	12.57	14.50	13.10
1,500	208.95	187.95	216.85	195.85	7.90	3.78	7.90	4.20	13.93	12.53	14.46	13.06
1,600	222.28	199.88	230.64	208.24	8.36	3.76	8.36	4.18	13.89	12.49	14.42	13.02
1,700	235.61	211.81	244.43	220.63	8.82	3.74	8.82	4.16	13.86	12.46	14.38	12.98
1,800	248.94	223.74	258.22	233.02	9.28	3.73	9.28	4.15	13.83	12.43	14.35	12.95
1,900	262.27	235.67	272.01	245.41	9.74	3.71	9.74	4.13	13.80	12.40	14.32	12.92
2,000	275.60	247.60	285.80	257.80	10.20	3.70	10.20	4.12	13.78	12.38	14.29	12.89

Comparison of Present and Proposed
Small General Service (41)

Present			**Proposed**		
Service Charge	$14.00	/mo.	Fixed Charge	$15.00	/mo.
Energy Charge			Energy Charge		
Summer	$0.12690	kWh	Summer	$0.13750	kWh
Other	$0.11290	kWh	Other	$0.12350	kWh
RTA Charge	$0.00250	kWh			

					Present vs. Proposed				Average Rate			
kWh/	Present		Proposed Billing		Summer		Other		Present		Proposed	
Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
100	26.94	25.54	28.75	27.35	1.81	6.72	1.81	6.72	26.94	25.54	28.75	27.35
200	39.88	37.08	42.50	39.70	2.62	6.57	2.62	6.57	19.94	18.54	21.25	19.85
300	52.82	48.62	56.25	52.05	3.43	6.49	3.43	6.49	17.61	16.21	18.75	17.35
400	65.76	60.16	70.00	64.40	4.24	6.45	4.24	6.45	16.44	15.04	17.50	16.10
500	78.70	71.70	83.75	76.75	5.05	6.42	5.05	6.42	15.74	14.34	16.75	15.35
600	91.64	83.24	97.50	89.10	5.86	6.39	5.86	6.39	15.27	13.87	16.25	14.85
700	104.58	94.78	111.25	101.45	6.67	6.38	6.67	6.38	14.94	13.54	15.89	14.49
800	117.52	106.32	125.00	113.80	7.48	6.36	7.48	6.36	14.69	13.29	15.63	14.23
900	130.46	117.86	138.75	126.15	8.29	6.35	8.29	6.35	14.50	13.10	15.42	14.02
1,000	143.40	129.40	152.50	138.50	9.10	6.35	9.10	6.35	14.34	12.94	15.25	13.85
1,100	156.34	140.94	166.25	150.85	9.91	6.34	9.91	6.34	14.21	12.81	15.11	13.71
1,200	169.28	152.48	180.00	163.20	10.72	6.33	10.72	6.33	14.11	12.71	15.00	13.60
1,300	182.22	164.02	193.75	175.55	11.53	6.33	11.53	6.33	14.02	12.62	14.90	13.50
1,400	195.16	175.56	207.50	187.90	12.34	6.32	12.34	6.32	13.94	12.54	14.82	13.42
1,500	208.10	187.10	221.25	200.25	13.15	6.32	13.15	6.32	13.87	12.47	14.75	13.35
2,000	272.80	244.80	290.00	262.00	17.20	6.30	17.20	6.30	13.64	12.24	14.50	13.10
2,500	337.50	302.50	358.75	323.75	21.25	6.30	21.25	6.30	13.50	12.10	14.35	12.95
3,000	402.20	360.20	427.50	385.50	25.30	6.29	25.30	6.29	13.41	12.01	14.25	12.85
3,500	466.90	417.90	496.25	447.25	29.35	6.29	29.35	6.29	13.34	11.94	14.18	12.78
4,000	531.60	475.60	565.00	509.00	33.40	6.28	33.40	6.28	13.29	11.89	14.13	12.73

Comparison of Present and Proposed
General Service (46)
Based on 40 kW

Present			**Proposed**		
Fixed Charge	$34.00	/mo.	Fixed Charge	$34.00	/mo.
Demand Charge			Demand Charge		
Summer	$12.26	/kW	Summer	$13.70	/kW
Other	$9.16	/kW	Other	$10.60	/kW
Energy Charge			Energy Charge		
First 200 kWh/kW	$0.07760	/kWh	First 200 kWh/k\	$0.07760	/kWh
Next 200 kWh/kW	$0.06760	/kWh	Next 200 kWh/k\	$0.06760	/kWh
Over 400 kWh/kW	$0.05760	/kWh	Over 400 kWh/k\	$0.05760	/kWh
RTA Charge	$0.0025	/kWh			

Avg		**Billing**				**Present vs. Proposed**				**Average Rate**			
Load	kWh/	Present		Proposed		Summer		Other		Present		Proposed	
Factor	Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(%)	(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
-	-	524.40	400.40	582.00	458.00	57.60	10.98	57.60	14.39	N.A.	N.A.	N.A.	N.A.
5	1,460	641.35	517.35	695.30	571.30	53.95	8.41	53.95	10.43	43.93	35.43	47.62	39.13
10	2,920	758.29	634.29	808.59	684.59	50.30	6.63	50.30	7.93	25.97	21.72	27.69	23.44
15	4,380	875.24	751.24	921.89	797.89	46.65	5.33	46.65	6.21	19.98	17.15	21.05	18.22
20	5,840	992.18	868.18	1,035.18	911.18	43.00	4.33	43.00	4.95	16.99	14.87	17.73	15.60
25	7,300	1,109.13	985.13	1,148.48	1,024.48	39.35	3.55	39.35	3.99	15.19	13.49	15.73	14.03
30	8,760	1,218.48	1,094.48	1,254.18	1,130.18	35.70	2.93	35.70	3.26	13.91	12.49	14.32	12.90
35	10,220	1,320.82	1,196.82	1,352.87	1,228.87	32.05	2.43	32.05	2.68	12.92	11.71	13.24	12.02
40	11,680	1,423.17	1,299.17	1,451.57	1,327.57	28.40	2.00	28.40	2.19	12.18	11.12	12.43	11.37
45	13,140	1,525.51	1,401.51	1,550.26	1,426.26	24.75	1.62	24.75	1.77	11.61	10.67	11.80	10.85
50	14,600	1,627.86	1,503.86	1,648.96	1,524.96	21.10	1.30	21.10	1.40	11.15	10.30	11.29	10.44
55	16,060	1,729.61	1,605.61	1,747.06	1,623.06	17.45	1.01	17.45	1.09	10.77	10.00	10.88	10.11
60	17,520	1,817.35	1,693.35	1,831.15	1,707.15	13.80	0.76	13.80	0.81	10.37	9.67	10.45	9.74
65	18,980	1,905.10	1,781.10	1,915.25	1,791.25	10.15	0.53	10.15	0.57	10.04	9.38	10.09	9.44
70	20,440	1,992.84	1,868.84	1,999.34	1,875.34	6.50	0.33	6.50	0.35	9.75	9.14	9.78	9.17
75	21,900	2,080.59	1,956.59	2,083.44	1,959.44	2.85	0.14	2.85	0.15	9.50	8.93	9.51	8.95
80	23,360	2,168.34	2,044.34	2,167.54	2,043.54	(0.80)	(0.04)	(0.80)	(0.04)	9.28	8.75	9.28	8.75
85	24,820	2,256.08	2,132.08	2,251.63	2,127.63	(4.45)	(0.20)	(4.45)	(0.21)	9.09	8.59	9.07	8.5[illegible]
90	26,280	2,343.83	2,219.83	2,335.73	2,211.73	(8.10)	(0.35)	(8.10)	(0.36)	8.92	8.45	8.89	8.4[illegible]
95	27,740	2,431.57	2,307.57	2,419.82	2,295.82	(11.75)	(0.48)	(11.75)	(0.51)	8.77	8.32	8.72	8.2[illegible]
100	29,200	2,519.32	2,395.32	2,503.92	2,379.92	(15.40)	(0.61)	(15.40)	(0.64)	8.63	8.20	8.58	8.15

Comparison of Present and Proposed
General Service (46)
Based on 230 kW

Present			**Proposed**		
Fixed Charge	$34.00	/mo.	Fixed Charge	$34.00	/mo.
Demand Charge			Demand Charge		
Summer	$12.26	/kW	Summer	$13.70	/kW
Other	$9.16	/kW	Other	$10.60	/kW
Energy Charge			Energy Charge		/kWh
First 200 kWh/kW	$0.07760	/kWh	First 200 kWh/k\	$0.07760	
Next 200 kWh/kW	$0.06760	/kWh	Next 200 kWh/k\	$0.06760	
Over 400 kWh/kW	$0.05760	/kWh	Over 400 kWh/k\	$0.05760	
RTA Charge	$0.00250	/kWh			

Avg.		Billing				Present vs. Proposed				Average Rate			
Load	kWh/	Present		Proposed		Summer		Other		Present		Proposed	
Factor	Mo.	Summer	Other	Summer	Other	Incr./(Decr.)		Incr./(Decr.)		Summer	Other	Summer	Other
(%)	(kWh/mo)	($)	($)	($)	($)	($)	(%)	($)	(%)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
-	-	2,853.80	2,140.80	3,185.00	2,472.00	331.20	11.61	331.20	15.47	N.A.	N.A.	N.A.	N.A.
5	8,395	3,526.24	2,813.24	3,836.45	3,123.45	310.21	8.80	310.21	11.03	42.00	33.51	45.70	37.21
10	16,790	4,198.68	3,485.68	4,487.90	3,774.90	289.22	6.89	289.22	8.30	25.01	20.76	26.73	22.48
15	25,185	4,871.12	4,158.12	5,139.36	4,426.36	268.24	5.51	268.24	6.45	19.34	16.51	20.41	17.58
20	33,580	5,543.56	4,830.56	5,790.81	5,077.81	247.25	4.46	247.25	5.12	16.51	14.39	17.24	15.12
25	41,975	6,216.00	5,503.00	6,442.26	5,729.26	226.26	3.64	226.26	4.11	14.81	13.11	15.35	13.65
30	50,370	6,844.74	6,131.74	7,050.01	6,337.01	205.27	3.00	205.27	3.35	13.59	12.17	14.00	12.58
35	58,765	7,433.23	6,720.23	7,617.51	6,904.51	184.29	2.48	184.29	2.74	12.65	11.44	12.96	11.75
40	67,160	8,021.72	7,308.72	8,185.02	7,472.02	163.30	2.04	163.30	2.23	11.94	10.88	12.19	11.13
45	75,555	8,610.21	7,897.21	8,752.52	8,039.52	142.31	1.65	142.31	1.80	11.40	10.45	11.58	10.64
50	83,950	9,198.70	8,485.70	9,320.02	8,607.02	121.32	1.32	121.32	1.43	10.96	10.11	11.10	10.25
55	92,345	9,783.73	9,070.73	9,884.07	9,171.07	100.34	1.03	100.34	1.11	10.59	9.82	10.70	9.93
60	100,740	10,288.27	9,575.27	10,367.62	9,654.62	79.35	0.77	79.35	0.83	10.21	9.50	10.29	9.58
65	109,135	10,792.81	10,079.81	10,851.18	10,138.18	58.36	0.54	58.36	0.58	9.89	9.24	9.94	9.29
70	117,530	11,297.35	10,584.35	11,334.73	10,621.73	37.37	0.33	37.37	0.35	9.61	9.01	9.64	9.04
75	125,925	11,801.89	11,088.89	11,818.28	11,105.28	16.39	0.14	16.39	0.15	9.37	8.81	9.39	8.82
80	134,320	12,306.43	11,593.43	12,301.83	11,588.83	(4.60)	(0.04)	(4.60)	(0.04)	9.16	8.63	9.16	8.63
85	142,715	12,810.97	12,097.97	12,785.38	12,072.38	(25.59)	(0.20)	(25.59)	(0.21)	8.98	8.48	8.96	8.46
90	151,110	13,315.51	12,602.51	13,268.94	12,555.94	(46.58)	(0.35)	(46.58)	(0.37)	8.81	8.34	8.78	8.31
95	159,505	13,820.05	13,107.05	13,752.49	13,039.49	(67.56)	(0.49)	(67.56)	(0.52)	8.66	8.22	8.62	8.17
100	167,900	14,324.59	13,611.59	14,236.04	13,523.04	(88.55)	(0.62)	(88.55)	(0.65)	8.53	8.11	8.48	8.05

Comparison of Present and Proposed Rates
Full Interruptible Service (70)
Based on 450 kW - Assume Zero Coincidental Demand

Present			**Proposed**		
Fixed Charge	$110.00	/mo.	Fixed Charge	$130.00	/mo.
Demand Charge			Demand Charge		
Summer	$24.85	/kW	Summer	$26.14	/kW
Winter	$18.95	/kW	Winter	$19.91	/kW
Other	$13.00	/kW	Other	$13.67	/kW
Non-coinc	$4.75	/kW	Non-coinc	$5.25	/kW
Energy Charge	$0.04990	/kWh	Energy Charge	$0.05210	/kWh
RTA Charge	(0.0005)	/kWh			

Avg. Load Factor	kWh/ Mo.	Billing Present	Billing Proposed	Present vs. Proposed Incr./(Decr.)	Present vs. Proposed Incr./(Decr.)	Average Rate Present	Average Rate Proposed
(%)	(kWh/mo)	($)	($)	($)	(%)	(¢/kWh)	(¢/kWh)
-	-	2,247.50	2,492.50	245.00	10.90	N.A.	N.A.
5	16,425	3,058.90	3,348.24	289.34	9.46	18.62	20.39
10	32,850	3,870.29	4,203.99	333.70	8.62	11.78	12.80
15	49,275	4,681.69	5,059.73	378.04	8.07	9.50	10.27
20	65,700	5,493.08	5,915.47	422.39	7.69	8.36	9.00
25	82,125	6,304.48	6,771.21	466.73	7.40	7.68	8.25
30	98,550	7,115.87	7,626.96	511.09	7.18	7.22	7.74
35	114,975	7,927.27	8,482.70	555.43	7.01	6.89	7.38
40	131,400	8,738.66	9,338.44	599.78	6.86	6.65	7.11
45	147,825	9,550.06	10,194.18	644.12	6.74	6.46	6.90
50	164,250	10,361.45	11,049.93	688.48	6.64	6.31	6.73
55	180,675	11,172.85	11,905.67	732.82	6.56	6.18	6.59
60	197,100	11,984.24	12,761.41	777.17	6.48	6.08	6.47
65	213,525	12,795.64	13,617.15	821.51	6.42	5.99	6.38
70	229,950	13,607.03	14,472.90	865.87	6.36	5.92	6.29
75	246,375	14,418.43	15,328.64	910.21	6.31	5.85	6.22
80	262,800	15,229.82	16,184.38	954.56	6.27	5.80	6.16
85	279,225	16,041.22	17,040.12	998.90	6.23	5.74	6.10
90	295,650	16,852.61	17,895.87	1,043.26	6.19	5.70	6.05
95	312,075	17,664.01	18,751.61	1,087.60	6.16	5.66	6.01
100	328,500	18,475.40	19,607.35	1,131.95	6.13	5.62	5.97

Docket No. E-111/GR-19-478

Exhibit__(DEA-5)
Statement of Operations -
Proposed Rates

Statement of Operations
Proposed Rates
Test Year - 2018 Historical Adjusted

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Adjustments [1]	(e) Pro Forma Test Year
1	**Operating Revenue**	($)	($)	($)
2	Rate Schedules	202,630,477	6,498,007	209,128,484 [2]
3	Other	508,198	626,590	1,134,788
4	**Total Operating Revenue**	203,138,675	7,124,597	210,263,272
5	**Operating Expenses**			
6	Cost of Purchased Power	149,330,034	1,319,432	150,649,466
7	Transmission - O & M	-		-
8	Distribution - Operation	7,277,184	(383,045)	6,894,139
9	Distribution - Maintenance	6,151,338	242,574	6,393,912
10	Consumer Accounts	5,312,955	380,854	5,693,809
11	Consumer Service & Information	3,585,760	(180,461)	3,405,299
12	Sales	-	-	-
13	Administrative & General	11,907,838	71,783	11,979,621
14	Depreciation & Amortization	10,281,975	404,073	10,686,048
15	Taxes - Property	3,372,283	178,507	3,550,790
16	Taxes - Other	-	-	-
17	Other Interest Expense	549,008	-	549,008
18	Other Deductions	6,239	(38,705)	(32,466)
19	**Total Operating Expenses** (Before Long Term Interest)	197,774,614	1,995,012	199,769,626
20	**Net Operating Income** (Before Long Term Interest)	5,364,061	5,129,585	10,493,646

[1] The operating expense adjustments are summarized on page 2 of Exhibit__(DEA-1).
[2] See pages 2 through 10 for an estimate of the Pro Forma Test Year revenue under proposed rates.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

I. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons.	(d) Energy Sales [1] (kWh)	(e) Billing Demand (kW)	(f) Revenue [2] ($)
1	Residential & Farm Service (31)	100,202	838,089,528	N.A.	119,389,671
2	Residential & Farm Demand Control (32)	15	378,000	917.2	44,529
3	Electric Vehicle (33)	88	300,960	N.A.	26,505
4	Irrigation Service (36) Firm	8	162,528	1,867.3	50,484
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	883,153
6	Small General Service (41)	4,431	42,537,600	N.A.	6,197,337
7	Security Lighting Service (44) - Closed to New	878	405,600	N.A.	120,526
8	Street Lighting Service (44-2)	2,269	2,405,280	N.A.	524,779
9	Street Lighting System (44-1)	470	521,040	N.A.	88,142
10	Custom Residential Street Lighting (44-3)	12,190	6,750,960	N.A.	1,623,968
11	LED Security Lighting Service (44 -4)	356	64,896	N.A.	31,434
12	LED Street Lighting Member Owned(44-5)	11	8,712	N.A.	1,473
13	LED Street Lighting (44-6)	597	202,152	N.A.	57,768
14	Low Wattage Unmetered Service (45)	71	-	N.A.	8,946
15	General Service (46)	2,750	462,000,000	1,442,500.4	51,183,966
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	3	172,800	N.A.	17,798
18	Controlled Energy Storage (51)	1,718	10,308,000	N.A.	502,001
19	Controlled Interruptible Service (52)	6,686	44,127,600	N.A.	2,784,452
20	Residential & Farm Time of Day (53)	18	216,216	N.A.	30,323
21	General Service Time of Day (54)	6	1,059,984	6,802.3	130,543
22	Standby Service (60)	1	-	-	74,160
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	24,654,929
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,299,459
25	Cycled Air Conditioning Service (80)	41,880	379,080,000		(1,625,193)
26	Wellspring				23,370
27	**Total** [3]	108,168	1,824,313,200	2,496,964.3	209,128,484

[1] See Exhibit__(DEA-1), page 13.
[2] See Exhibit__(DEA-5), pages 3 through 9.
[3] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

II. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Residential & Farm Service (31)				($)
Fixed Charge	100,202	cons.	$10.00	12,024,240
Energy Charge				
Summer	257,025,312	kWh	$0.13790	35,443,791
Other	581,064,216	kWh	$0.12390	71,993,856
	838,089,528	kWh	Subtotal	119,461,887
RTA Charge [1]	838,089,528	kWh		
Controlled Water Heater Credit	1,003	units	($6.00)	(72,216)
			Total	119,389,671
Residential & Farm Demand Control (32)				
Fixed Charge	15	cons.	$13.00	2,340
Demand Charge				
Summer	182.2	kW	$15.50	2,824
Other	735.0	kW	$11.90	8,747
Energy Charge	378,000	kWh	$0.08100	30,618
			Subtotal	44,529
RTA Charge [1]	378,000	kWh		
			Total	44,529
Electric Vehicle (33)				
Energy Charge				
Off Peak	280,402	kWh	$0.07560	21,198
On Peak	8,554	kWh	$0.44210	3,782
Other				
Summer	2,693	kWh	$0.13790	371
Other	9,311	kWh	$0.12390	1,154
			Subtotal	26,505
RTA Charge [1]	300,960	kWh		
				26,505
Irrigation Service (36)				
Firm Service				
Fixed Charge	8	cons.	$30.00	2,880
Demand Charge				
Summer	902.3	kW	$26.60	24,001
Winter	2.5	kW	$21.20	53
Other	962.5	kW	$15.67	15,082
Energy Charge	162,528	kWh	$0.05210	8,468
RTA Charge [1]	162,528	kWh		
			Total	50,484

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

II. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Irrigation Service (36)				
Interruptible Service				
Fixed Charge	384	cons.	$30.00	138,240
Demand Charge	74,388	kW	$4.55	338,463
Energy Charge	7,801,344	kWh	$0.05210	406,450
RTA Charge [1]	7,801,344	kWh		
			Total	883,153
Small General Service (41)				
Fixed Charge				
Energy Charge	4,431	cons.	$15.00	797,580
Summer	10,541,910	kWh	$0.13750	1,449,513
Other	31,995,690	kWh	$0.12350	3,951,468
	42,537,600	kWh	Subtotal	6,198,561
RTA Charge [1]	42,537,600	kWh		
Controlled Water Heater Credit	17	units	($6.00)	($1,224)
			Total	6,197,337
Security Lighting Service (44) - Closed to New				
175 W MV		lights	N/A	
100 W HPS	819	lights	$12.01	118,034
150 W HPS	4	lights	$14.26	684
250 W HPS	8	lights	$18.83	1,808
	831	lights	Subtotal	120,526
RTA Charge [1]	405,600	kWh		
			Total	120,526
Street Lighting Service (44-2)				
175 W MV		lights	$17.44	
250 W MV	3	lights	$20.93	753
400 W MV		lights	$26.89	
100 W HPS	38	lights	$13.80	6,293
150 W HPS	646	lights	$15.97	123,799
250 W HPS	1,597	lights	$20.54	393,629
400 W HPS	1	lights	$25.42	305
	2,285	lights	Subtotal	524,779
RTA Charge [1]	2,405,280	kWh		
			Total	524,779

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Street Lighting System (44-1)				($)
175 W MV		lights	$13.25	
250 W MV		lights	$16.74	
400 W MV		lights	$22.71	
100 W HPS		lights	$9.61	
150 W HPS	101	lights	$11.78	14,277
200 W HPS	101	lights	$14.18	17,186
250 W HPS	272	lights	$16.35	53,366
400 W HPS	13	lights	$21.24	3,313
	487	lights	Subtotal	88,142
RTA Charge [1]	521,040	kWh		
			Total	88,142
Custom Residential Street Lighting (44-3)				
175 W MV		lights	$14.03	
50 W HPS	81	lights	$8.45	8,213
100 W HPS	8,416	lights	$10.39	1,049,307
150 W HPS	3,732	lights	$12.63	565,622
250 W HPS	4	lights	$17.21	826
	12,233	lights	Subtotal	1,623,968
RTA Charge [1]	6,750,960	kWh		
			Total	1,623,968
LED Security Lighting Service (44 -4)				
LED, >4,500 Lumens	338	lights	$7.75	31,434
RTA Charge [1]	64,896	kWh		
			Total	31,434

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
LED Street Lighting Member Owned(44-5)				($)
A (40-80 watts)		lights	$5.50	
B (81-150 watts)		lights	$7.75	
C (151-250 watts)	11	lights	$11.16	1,473
D (251-350 watts)		lights	$15.04	
E (351-450 watts)		lights	$19.07	
				1,473
RTA Charge [1]	8,712	kWh		
				1,473
LED Street Lighting (44-6)				
Standard				
>5,200 L, Coach (Post)	121	lights	$9.30	13,504
>5,200 L, Acorn (Post)	48	lights	$10.85	6,250
>7,000 L, Cobra (Mast)	91	lights	$8.60	9,391
>11,500 L, Shoebox	151	lights	$10.70	19,388
Basic				
>5,200 L, Coach (Post)	41	lights	$6.36	3,129
>5,200 L, Acorn (Post)		lights	$6.12	
>7,000 L, Cobra (Mast)	53	lights	$6.98	4,439
>11,500 L, Shoebox	16	lights	$8.68	1,667
				57,768
RTA Charge [1]	202,152	kWh		
				57,768
Low Wattage Unmetered Service (45)				
Fixed Charge	71	cons.	$10.50	8,946

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
General Service (46)				
Fixed Charge	2,750	cons.	$34.00	1,122,000
Demand Charge	1,442,500.4	kW		
Summer	413,627.7			
Summer Load Adjustment	(11,771.4)			
Net Summer	401,856.3	kW	$13.70	5,666,699
Other	1,028,872.7			
Other Load Adjustment	(21,406.1)			
Net Other	1,007,466.6	kW	$10.60	10,906,051
Energy Charge				
First 200 kWh/kW	264,418,387	kWh	$0.07760	20,518,867
Next 200 kWh/kW	158,964,776	kWh	$0.06760	10,746,019
Over 400 kWh/kW	38,616,837	kWh	$0.05760	2,224,330
			Subtotal	51,183,966
Discounts				
Primary Voltage			($0.15)	
Primary Metering			(2.00%)	
RTA Charge 1	462,000,000			
			Total	51,183,966
Municipal Civil Defense Sirens (47)		kWh		
Fixed Charge	66	cons.	$5.00	3,960
Geothermal Heat Pump (49)				
Energy Charge	172,800	kWh	$0.10300	17,798
RTA Charge [1]	172,800	kWh		
			Total	17,798
Controlled Energy Storage (51)				
Energy Net Charge - Rate 31				
Summer	2,701,434	kWh	$0.04870	131,560
Other	7,509,011	kWh	$0.04870	365,689
Energy Charge - Rate 41				
Summer	6,874	kWh	$0.04870	335
Other	39,232	kWh	$0.04870	1,911
Energy Charge - Rate 46	51,449	kWh	$0.04870	2,506
			Subtotal	502,001
RTA Charge [1]	10,308,000	kWh	NA	
			Total	502,001

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Controlled Interruptible Service (52)				($)
Energy Net Charge - Rate 31				
Summer	10,488,495	kWh	$ 0.0631	661,824
Other	32,538,130	kWh	0.0631	2,053,156
Energy Charge - Rate 41		kWh		
Summer	64,095	kWh	$0.06310	4,044
Other	386,791	kWh	$0.06310	24,407
Energy Charge - Rate 46	650,089		$0.06310	41,021
RTA Charge [1]	44,127,600		NA	
			Total	2,784,452
Residential & Farm Time of Day (53)				
Fixed Charge	18	cons.	$13.00	2,808
Energy Charge				
Peak Period				
Summer	49,267	kWh	$0.21263	10,476
Other	12,117	kWh	$0.19863	2,407
Off-Peak Period	154,832	kWh	$0.09450	14,632
	216,216	kWh	Subtotal	30,323
RTA Charge [1]	216,216	kWh		
			Total	30,323
General Service Time of Day (54)				
Fixed Charge	6	cons.	$36.00	2,592
Demand Charge				
Peak Period				
Summer	960.1	kW	$26.14	25,097
Winter	436.9	kW	$19.91	8,699
Other	1,253.2	kW	$13.67	17,131
	2,650.2	kW		
Maximum	4,152.1	kW	$5.25	21,799
Energy Charge	1,059,984	kWh	$0.05210	55,225
			Subtotal	130,543
Discounts				
Primary Voltage		kW	($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	1,059,984	kWh		
			Total	130,543

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Standby Service (60)				
Generation Reservation Fee				
Summer	1,000	kW	$3.21	9,630
Winter	1,000	kW	$2.47	7,410
Other	1,000	kW	$1.74	10,440
Distribution Reservation Fee				
Primary	1,000	kW	$3.89	46,680
Secondary		kW	$4.02	
			Total	74,160
Full Interruptible Service (70)				
Fixed Charge	234	cons.	$130.00	365,040
Communication Fee	51		$8.70	5,324
Coinc. Demand Charge				
Summer	1,042.8	kW	$26.14	27,259
Winter		kW	$19.91	
Other		kW	$13.67	
Total Coinc Demand	1,042.8	kW		
Non-Coinc. Demand	858,880.1	kW	$5.25	4,509,121
Failure to Control	1,042.8	kW	$5.00	5,214
Energy Charge	379,080,000	kWh	$0.05210	19,750,068
Discounts			Subtotal	24,662,026
Primary Voltage	47,311.1	kW	($0.15)	($7,097)
Primary Metering			(2.0%)	
RTA Charge [1]	379,080,000	kWh		
			Total	24,654,929
Partial Interruptible Service (71)				
Fixed Charge	28	cons.	$130.00	43,680
Communication Fee	17		$8.70	1,775
Coinc. Demand Charge				
Summer	3,212.2	kW	$26.14	83,967
Winter	2,980.2	kW	$19.91	59,336
Other	5,964.3	kW	$13.67	81,532
Total Coinc Demand	12,156.7	kW		
Non-Coinc. Demand	111,609.5	kW	$5.25	585,950
Excess Demand		kW	$5.00	
Energy Charge	27,720,000	kWh	$0.05210	1,444,212
Discounts			Subtotal	2,300,452
Primary Voltage	6,623	kW	$0.15	(993)
Primary Metering			2.0%	-
RTA Charge [1]	27,720,000	kWh		
			Total	2,299,459

[1] Proposed rates assume zero RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Proposed Rates
(Continued)

III. Estimate of Revenue Under Proposed Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Cycled Air Conditioning Service (80)				
Option 1		kWh		
Option 2				
Residential Rate 8131	4,858,654	kWh	($0.03200)	(155,477)
Rate 8141	216,346	kWh	($0.03200)	(6,923)
Rate 8146		kWh	($0.03200)	
	5,075,000	kWh		(162,400)
Option 3				
Residential Rate 8231	35,158	cons.	($13.00)	(1,371,162)
Commercial		cons.	($13.00)	
				(1,371,162)
Option 4				
Rate 8441	4,699	tons	($6.50)	(91,631)
Rate 8446		tons	($6.50)	
	4,699			(91,631)
				(1,625,193)
			Total	
Wellspring				23,370
Grand Total	1,824,313,200			209,128,484

[1] Proposed rates assume zero RTA.

Docket No. E-111/GR-19-478

Exhibit__(DEA-4)
Load Management Cost Analysis

Summary of Cost of Service Analysis
Load Management Rates
I. Summary

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Rate Description	**GRE Rate** (¢/kWh)	**Line Losses** (¢/kWh)	**Meter & Control** (¢/kWh)	**Allocated Distribution** (¢/kWh)	**Margin** (¢/kWh)	**Total Cost** (¢/kWh)	**Weighted Sales** (%)	**Retail Rate** (¢/kWh)
Schedule 49								
Geothermal Heat Pump	8.13 [2]	0.12	0.42	2.13	0.27	11.07	100%	**11.07**
Schedule 51 (Storage)								
ETS-Water Heating (16 hr)	2.00	0.12	0.42	2.13	0.07	4.74	49%	2.32
ETS-Storage [1]	2.25	0.12	0.42	2.13	0.08	5.00	51%	2.55
							Schedule 51 Rate	**4.87**
Schedule 52 (Interruptible)								
Peak Shave - Water (8 hr)	3.40	0.12	0.42	2.13	0.11	6.18	53%	3.28
Dual Fuel - Space Heating	3.65	0.12	0.42	2.13	0.12	6.44	47%	3.03
							Schedule 52 Rate	**6.31**

Col.	**Notes**
(a)	Load management rates per GRE's present wholesale rate schedules.
(b)	Based on GRE wholesale rate schedules for Year 2019.
(c)	GRE General Service Energy Rate x 2.50% which represents the average losses for the system.
(d)	See page 2.
(e)	See page 4.
(f)	See page 3 for calculation of margin.
(g)	Sum Col. (b) to Col. (f).
(h)	Relative (percent) energy sales under each GRE special program. See Exhibit __ (DEA-1) Page 22 of 22.
(i)	Equals Total Cost times Weighted Sales. Sum equals retail rate of each schedule.

[1] This rate may also apply to loads qualifying under the ETS Pool Heating program and/or Electric Vehicles program.
[2] Geothermal equals GRE average energy rate plus average system capacity, transmission, and ancillary services costs on a per kWh basis.

Cost of Service Analysis
Load Management Rates
(Continued)

II. Cost of Service Analysis

A. Incremental Cost of Service

1. Annual Cost of Control Unit and Meter
   a. Investment

1. Meter	$53
2. Control Unit	$134
3. Subtotal	$187

   b. Annual Cost Factor
      1. Capital Recovery Factor [1]

$$\frac{0.0420 \times (1.0420)^{15}}{1.0420^{15} - 1} = 9.1\%$$

      2. Operation & Maintenance

O & M Expense / Dist. Plant [2]	$13,288,051 / $267,355,082	=	5.0%
	Total		14.1%

c. Annual Cost	$187.00	x	14.1%	=	$26.35	/year
d. Per kWh Cost [3]					0.42	¢/kWh

2. Purchased Power
   a. At present wholesale energy rate adjusted for load management programs. See Page 1.

   b. Average system losses for test year = 2.50%

[1] The incremental interest rate is estimated as follows:

CFC-15 yr	1.00	x	4.2000%	=	4.2000%

[2] Data taken from Form 7 for December, 2018. See workpaper 1.

[3] Based on annual use of 6,300 kWh per year.

Cost of Service Analysis
Load Management Rates
(Continued)

II. Cost of Service Analysis (Continued)

A. Incremental Cost of Service (Continued)

3. Margin Requirement (Equity Portion Only) [1]

$$\frac{\text{Required Net Operating Income - Interest Expense}}{\text{Total Expenses + Required Net Operating Income}}$$

$$\frac{\$10{,}538{,}868 \quad - \quad \$3{,}766{,}478}{\$199{,}769{,}626 \quad + \quad \$10{,}538{,}868} = 3.2202\%$$

B. Allocated Cost of Service (Full Share)

1. Distribution System Capacity

a. Depreciation (Acct. 403)		$10,686,048	
b. Interest (Acct. 427)		3,766,478	
c. Operation and Maintenance (Accts. 580 to 598)		13,288,051	
d. Total		$27,740,577	
e. Energy Sales		1,824,313,200	kWh
f. Unit Cost (Unadjusted)		1.52	¢/kWh
g. Allocation Factor [2]	x	50.00%	
h. Allocation Cost		0.76	¢/kWh

2. Administration and General

$$\frac{\text{Accounts 920 to 930}}{\text{Total Energy Sales}} = \frac{\$11{,}979{,}621}{1{,}824{,}313{,}200 \text{ kWh}} = 0.66 \text{ ¢/kWh}$$

[1] Interest expense is reflected in the "annual cost factor". Margin is to cover the patronage capital which will be allocated to each consumer on the basis of all other costs which is somewhat analogous to revenue.

[2] Factor to be used to allocate distribution system related cost to the off-peak class. Use 0.5000 as this approximates the capacity related distribution system costs in the listed categories.

Cost of Service Analysis
Load Management Rates
(Continued)

B. Allocated Cost of Service (Full Share) (Continued)

3. Consumer Accounting

$$\frac{\text{Accounts 901 to 905 x Weight Factor}^{1}}{\text{Total No. of Cons. x Off-Peak Usage}}$$

$$\frac{\$5{,}693{,}809 \quad \text{x} \quad 0.50}{108{,}165 \quad \text{x} \quad 6{,}300 \ \text{kWh}^{2}}$$ 0.42 ¢/kWh

4. Taxes

$$\frac{\text{Account 408}}{\text{Total Energy Sales}}$$

$$\frac{\$3{,}550{,}790}{1{,}824{,}313{,}200 \ \text{kWh}}$$ 0.19 ¢/kWh

5. Consumer Service & Sales [3] 0.10 ¢/kWh

6. Total Allocated Costs (Before Margin Requirement) 2.13 ¢/kWh

[1] Use a weighting factor of 0.5 to represent the amount of consumer accounting expense to be allocated to this class.
[2] Estimate the annual usage for a typical system to be 6,300 kWh per year based on Pro Forma Test Year Sales.
[3] This factor is based on the judgment of management as to the special cost assocated with providing information and customer service for this type of load.

Docket No. E-111/GR-19-478

Exhibit (DEA-3)
Cost of Service Analysis

Cost of Service Summary
Revenue Requirements Summary

Line No.	Description	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Revenue Requirements**							
2	Revenue Requirements	207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469
3								
4	**Present Rates**							
5	Revenue-Present Rates	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
6	Other Operating Revenue	1,100,791	629,957	31,817	5,091	281,211	141,172	11,543
7	Total Revenue	198,343,047	113,507,080	5,732,872	917,323	50,669,263	25,436,728	2,079,781
8								
9	Difference	8,727,396	5,968,415	509,411	(24,816)	(132,811)	2,018,508	388,689
10	Percent		5.29%	8.94%	(2.72%)	(0.26%)	7.98%	18.79%

Cost of Service Summary
Class Allocation Summary

Line No.	Category	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Power Supply**							
2	**Direct and Revenue Related**							
3	Wholesale Cost							
4	Allocated Cost							
5	Subtotal							
6	**Capacity Related**							
7	Wholesale Cost	33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
8	Allocated Cost	328,991	198,146	10,188	183	105,776	12,878	1,819
9	Subtotal	33,843,058	20,979,277	1,042,559	25,042	11,476,666	162,728	156,786
10	**Energy Related**							
11	Wholesale Cost	92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
12	Allocated Cost	892,910	420,872	21,278	4,042	235,006	206,454	5,257
13	Subtotal	93,803,557	44,478,179	2,255,842	422,396	24,560,237	21,576,264	510,639
14	Subtotal Power Supply	127,646,615	65,457,456	3,298,400	447,438	36,036,904	21,738,992	667,425
15	**Transmission**							
16	Direct							
17	Capacity	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
18	Energy							
19	Allocated Cost							
20	Subtotal Transmission	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
21	**Distribution**							
22	Direct	1,446,444						1,446,444
23	Consumer	35,017,518	30,207,652	1,736,178	269,591	2,007,933	695,080	101,085
24	Capacity	20,310,243	10,113,625	501,599	162,967	5,261,940	4,140,938	129,175
25	Energy							
26	Subtotal Distribution	56,774,205	40,321,277	2,237,776	432,558	7,269,873	4,836,017	1,676,703
27								
28	**Total**	207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Cost of Service Summary
Rate Design Factors

Line No.	Category	Units	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Costs Broken Down by Function**							
2	**Power Supply**							
3	**Direct and Revenue Related**							
4	Wholesale Cost	$/Mo./cons						
5	Allocated Cost	$/Mo./cons						
6	Subtotal							
7	**Capacity Related**							
8	Wholesale Cost	¢/kWh	2.48	2.43	0.31	2.46	0.04	1.50
9	Allocated Cost	¢/kWh	0.02	0.02	0.00	0.02	0.00	0.02
10	Subtotal	¢/kWh	2.50	2.45	0.31	2.48	0.04	1.51
11	**Energy Related**							
12	Wholesale Cost	¢/kWh	5.25	5.25	5.25	5.25	5.25	4.88
13	Allocated Cost	¢/kWh	0.05	0.05	0.05	0.05	0.05	0.05
14	Subtotal	¢/kWh	5.30	5.30	5.30	5.30	5.30	4.93
15	Subtotal Power Supply	¢/kWh	7.80	7.75	5.62	7.78	5.34	6.44
16	**Transmission**							
17	Direct	¢/kWh						
18	Capacity	¢/kWh	1.63	1.66	0.16	1.56	0.22	1.20
19	Energy	¢/kWh						
20	Allocated Cost	¢/kWh						
21	Subtotal Transmission	¢/kWh	1.63	1.66	0.16	1.56	0.22	1.20
22	**Distribution**							
23	Direct	$/Mo./cons						7.19
24	Consumer	$/Mo./cons	25.11	32.65	57.31	60.71	221.08	0.50
25	Capacity	¢/kWh	1.21	1.18	2.05	1.14	1.02	1.25
26	Energy	¢/kWh						
27	Subtotal Distribution	¢/kWh	4.81	5.26	5.43	1.57	1.19	16.19
28	**Total**	¢/kWh	14.25	14.67	11.21	10.91	6.75	23.83
29	**Costs Broken Down by Classification**							
30	Direct	$/Mo./cons						7.19
31	Consumer	$/Mo./cons	25.11	32.65	57.31	60.71	221.08	0.50
32	Capacity	¢/kWh	5.34	5.29	2.52	5.18	1.27	3.96
33	Energy	¢/kWh	5.30	5.30	5.30	5.30	5.30	4.93
34	**Total**		14.25	14.67	11.21	10.91	6.75	23.83

Classification of Plant in Service (Net)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Net Intangible Plant**																
2	301	Organization	PLNT															
3	302	Franchises and consents	PLNT															
4	303	Miscellaneous intangible plant	PLNT															
5	301-303	Subtotal																
6																		
7		**Net Production Plant**																
8	310-346	Production Plant	PROD1															
9																		
10		**Net Transmission Plant**																
11	350-359	Transmission Plant	TRAN1															
12																		
13		**Net Distribution Plant**																
14	360	Land	LAND	4,163,712					4,163,712									
15	361	Structures	SUB															
16	362	Station	SUB	18,856,408					18,856,408									
17	363	Battery	SUB															
18	364	Poles, towers	POLES	10,796,888							4,750,137	6,046,751						
19	365	OH Cond	PRI-OH	13,738,437							2,414,494	11,323,943						
20	366	UG Conduit	PRI-UG															
21	367	UG Cond	PRI-UG	84,374,330							63,512,819	20,861,511						
22	368	Transf	TRF	17,481,215									3,443,783	14,037,432				
23	369	Services	SERV	1,190,394											1,190,394			
24	370	Meters	MTR	2,686,182												2,686,182		
25	371	Cons Premise	ICON	123,745														
26	372	Leased Prop	LICON															
27	373	St. Light	STL	4,543,471														
28	360-373	Subtotal		157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
29																		
30		**Net General Plant**																
31	389	Land & Land Rights	PLNT	102,278					14,906		45,765	24,756	2,230	9,089	771	1,739		
32	390	Structures and Improve.	PLNT	4,601,923					670,678		2,059,148	1,113,874	100,333	408,973	34,681	78,260		
33	391	Office Furniture & Equip.	PLNT	5,056,678					736,954		2,262,629	1,223,945	110,247	449,387	38,109	85,994		
34	392	Transportation & Equipment	PLNT	918,591					133,874		411,027	222,341	20,027	81,635	6,923	15,622		
35	393	Stores Equipment	PLNT	18,982					2,766		8,494	4,595	414	1,687	143	323		
36	394	Tool, Shop & Garage Equip.	PLNT	156,304					22,780		69,939	37,833	3,408	13,891	1,178	2,658		
37	395	Laboratory Equipment	PLNT	209,246					30,495		93,628	50,647	4,562	18,596	1,577	3,558		
38	396	Power Operated Equipment	PLNT	3,930,565					572,835		1,758,746	951,375	85,695	349,309	29,622	66,843		
39	397	Communication Equipment	PLNT	345,799					50,396		154,729	83,699	7,539	30,731	2,606	5,881		
40	398	Miscellaneous Equipment	PLNT	84,672					12,340		37,887	20,495	1,846	7,525	638	1,440		
41	399	Other tangible property	PLNT	633,349					92,304		283,395	153,299	13,808	56,286	4,773	10,771		
42	389-399	Subtotal		16,058,389					2,340,328		7,185,385	3,886,857	350,110	1,427,108	121,021	273,089		
43																		
44		**Total Net Plant in Service**		174,013,170					25,360,448		77,862,835	42,119,061	3,793,893	15,464,540	1,311,415	2,959,271		

Classification of Plant in Service (Net)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
1		**Net Intangible Plant**								
2	301	Organization	PLNT							
3	302	Franchises and consents	PLNT							
4	303	Miscellaneous intangible plant	PLNT							
5	301-303	Subtotal								
6										
7		**Net Production Plant**								
8	310-346	Production Plant	PROD1							
9										
10		**Net Transmission Plant**								
11	350-359	Transmission Plant	TRAN1							
12										
13		**Net Distribution Plant**								
14	360	Land	LAND	4,163,712						
15	361	Structures	SUB							
16	362	Station	SUB	18,856,408						
17	363	Battery	SUB							
18	364	Poles, towers	POLES	10,796,888						
19	365	OH Cond	PRI-OH	13,738,437						
20	366	UG Conduit	PRI-UG							
21	367	UG Cond	PRI-UG	84,374,330						
22	368	Transf	TRF	17,481,215						
23	369	Services	SERV	1,190,394						
24	370	Meters	MTR	2,686,182						
25	371	Cons Premise	ICON	123,745						123,745
26	372	Leased Prop	LICON							
27	373	St. Light	STL	4,543,471						4,543,471
28	360-373	Subtotal		157,954,781						4,667,216
29										
30		**Net General Plant**								
31	389	Land & Land Rights	PLNT	102,278						3,022
32	390	Structures and Improve.	PLNT	4,601,923						135,977
33	391	Office Furniture & Equip.	PLNT	5,056,678						149,414
34	392	Transportation & Equipment	PLNT	918,591						27,142
35	393	Stores Equipment	PLNT	18,982						561
36	394	Tool, Shop & Garage Equip.	PLNT	156,304						4,618
37	395	Laboratory Equipment	PLNT	209,246						6,183
38	396	Power Operated Equipment	PLNT	3,930,565						116,140
39	397	Communication Equipment	PLNT	345,799						10,218
40	398	Miscellaneous Equipment	PLNT	84,672						2,502
41	399	Other tangible property	PLNT	633,349						18,714
42	389-399	Subtotal		16,058,389						474,490
43										
44		**Total Net Plant in Service**		174,013,170						5,141,706

Adjusted Statement of Operations
and Revenue Requirements

(a) Line No.	(b) Description	(c) Total System [1]	(d) Adjustment [2]	(e) Adjusted System
	Operating Revenue	($)	($)	($)
1	Rate Schedules	200,474,161	(3,238,029)	197,236,132
2	Other	1,100,791		1,100,791
3	Total Operating Revenue	201,574,952	(3,238,029)	198,336,923
4	**Operating Expenses**			
5	Cost of Purchased Power			
6	Substation	-	-	-
7	Transmission	20,496,973		20,496,973
8	Ancillary	2,152,650		2,152,650
9	Demand			-
10	Summer	17,112,830		17,112,830
11	Winter	8,390,047		8,390,047
12	Other	8,011,190		8,011,190
	Energy			-
13	Wholesale Solar	272,629		272,629
14	Energy On-Peak	36,623,232	(424,870)	36,198,362
15	Energy Off-Peak	57,584,525	(1,144,869)	56,439,656
16	Standby Reservation fee	27,060	(27,060)	-
16	Wellspring	23,370	(23,370)	-
	Member Specific Rate	(45,040)	45,040	-
16	Transmission - O & M		-	-
18	Distribution - Operation	6,894,139	(277,154)	6,616,985
19	Distribution - Maintenance	6,393,912	(277,154)	6,116,758
20	Consumer Accounts	5,693,809	-	5,693,809
21	Consumer Service & Information	3,405,299	-	3,405,299
22	Sales	-	-	-
23	Administrative & General	11,979,621	(277,154)	11,702,467
24	Depreciation & Amortization	10,686,048	(277,154)	10,408,894
25	Taxes - Property	3,550,790	-	3,550,790
26	Taxes - Other	-	-	-
27	Other Interest Expense	549,008	-	549,008
28	Other Deductions	(32,466)	-	(32,466)
29	**Total Operating Expenses (Before Long Term Interest)**	199,769,626	(2,683,745)	197,085,881
30	Long Term Interest [3]	3,766,478	(277,154)	3,489,324
31	Required Margin [4]	6,772,390	(277,152)	6,495,238
32	**Revenue Requirements**	210,308,494	(3,238,051)	207,070,443

[1] See Exhibit__(DEA-1), page 1.
[2] See page 7 for calculation of adjustment to exclude Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating Service, and Low Wattage Unmetered Service.
[3] See Workpaper 1.
[4] Required Net Operating Income less Long Term Interest. See calculation below:
$10,538,868 - $3,766,478 = $6,772,390

Adjustment to Eliminate Revenue and Expenses of Classes not included in the Base Cost of Service Study

1. Revenue [1]							($)
a.	Electric Vehicle (33)					=	24,636
b.	Municipal Civil Defense Sirens (47)					=	3,960
c.	Controlled Energy Storage (51)					=	459,736
d.	Controlled Interruptible Service (52)					=	2,634,418
e.	Low Wattage Unmetered Service (45)					=	8,520
f.	Geothermal Heat Pump (49) Closed to New					=	16,571
g.	Standby Service (60)					=	66,840
h.	Wellspring					=	23,370
i.	Total -- Revenue						3,238,051
2. Expenses							
a.	Purchased Power [2]						
	Energy:						
	Electric Vehicle (33)	264,300	kWh	x	0.0200	=	5,286
	Municipal Civil Defense Sirens (47)					=	-
	ETS-Interruptible Water Heating 3	6,187,000	kWh	x	0.02000	=	123,740
	Peak Shave Water Heating (8 hr) 3	21,206,900	kWh	x	0.03400	=	721,035
	ETS-Interruptible Space Heating 3	1,323,100	kWh	x	0.02250	=	29,770
	Dual Fuel 3	18,516,900	kWh	x	0.03650	=	675,867
	Geothermal Heat Pump	172,800	kWh	x	0.05087	=	8,790
	Subtotal -- Energy Expenses						1,564,488
	Standby	27,060	/year			=	27,060
	Wellspring	23,370	/year			=	23,370
	Member Specific Rate	(45,040)	/year			=	(45,040)
	Capacity - Geothermal	172,800	kWh	x	0.03039		5,251
	Subtotal -- Purchased Power Expenses						1,575,129
Remainder of Revenue to Allocate							1,662,922
b.	Distribution - Operation [3]					=	277,154
c.	Distribution - Maintenance [3]					=	277,154
d.	Administrative and General [3]					=	277,154
e.	Depreciation [3]					=	277,154
f.	Interest [3]					=	277,154
g.	Margin Requirements [3]					=	277,152
h.	Subtotal						1,662,922
i.	Total -- Expenses						3,238,051

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1 From Exhibit__(DEA-1), page 16.
2 From See Exhibit__(DEA-1), page 25.
3 Includes both Controlled Off-Peak Energy Storage (51) and Interruptible Heating Service (52).
4 Split remainder of revenue approximately equal between Distribution Operation and Maintenance, Administration and General, Depreciation and Interest.

Classification of Revenue Requirements

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Power Supply**																
2		**Production**																
3	500-557	Fuel	FUEL															
4	500-557	Non-Fuel O&M - Demand	PROD1															
5	500-557	Non-Fuel O&M - Energy	PROD1															
6		Subtotal - Production																
7		**Purchases**																
8	555	Direct Assign. Chgs (Cr.)																
9	555	Substation Charges	SUB															
10	555	Demand Charges	PURKW-1															
11	555	Summer	PURKW-2	17,112,830		17,885,414												
12	555	Winter	PURKW-3	8,390,047		8,390,047												
13	555	Other	PURKW-4	8,011,190		8,011,190												
14	555	Energy Charges - Critical Peak	PURKWH-1															
15	555	Energy Charges - On-Peak	PURKWH-2	36,393,097	36,393,097													
16	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550	56,517,550													
17	555	Standby Reservation Fee	REV															
18		Subtotal - Purchases		126,424,714	92,910,647	34,286,651												
19	500-557	Total Power Supply		126,424,714	92,910,647	34,286,651												
20																		
21		**Transmission**																
22	560-573	Operation & Maintenance	TRAN1															
23	555	Transmission - G&T Charges	TRAN2	22,649,623				22,649,623										
24		Total Transmission		22,649,623				22,649,623										
25																		
26		**Distribution**																
27	580	Oper. Super & Eng.	EX1															
28	581	Load Dispatch	EX1	1,410,722					265,542		227,970	98,059				819,151		
29	582	Oper. Station	SUB	631,828					631,828									
30	583	Oper. OH Line	PRI-OH	21,432							3,767	17,665						
31	584	Oper. UG Line	PRI-UG	703,799							529,785	174,014						
32	585	Oper. St. Lighting	STL															
33	586	Oper. Meters	MTR	1,949,081												1,949,081		
34	587	Oper. Cons. Install	ICON	50,520							8,879	41,642						
35	588	Oper. Misc. Oper.	EX1	1,849,603					348,153		298,892	128,565				1,073,992		
36	589	Rents	EX1															
37	590	Main. Super. & Eng.	EX2	4,204,506					371,258		667,009	3,128,264	7,481	30,493				
38	591	Main. Structure	SUB															
39	592	Main. Station	SUB	125,460					125,460									
40	593	Main. OH Line	PRI-OH	1,282,541							225,403	1,057,138						
41	594	Main. UG Line	PRI-UG															
42	595	Main. Line Transf.	TRF	12,832									2,528	10,304				
43	596	Main. St. Lighting	STL	491,419														
44	597	Main. Meters	MTR															
45	598	Main. Misc. Dist.	EX2															
46	580-598	Subtotal		12,733,743					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224		

Classification of Revenue Requirements

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
1		**Power Supply**								
2		**Production**								
3	500-557	Fuel	FUEL							
4	500-557	Non-Fuel O&M - Demand	PROD1							
5	500-557	Non-Fuel O&M - Energy	PROD1							
6		Subtotal - Production								
7		**Purchases**								
8	555	Direct Assign. Chgs (Cr.)								
9	555	Substation Charges	SUB							
10	555	Demand Charges	PURKW-1							
11	555	Summer	PURKW-2	17,112,830	(725,733)	(46,851)				
12	555	Winter	PURKW-3	8,390,047						
13	555	Other	PURKW-4	8,011,190						
14	555	Energy Charges - Critical Peak	PURKWH-1							
15	555	Energy Charges - On-Peak	PURKWH-2	36,393,097						
16	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550						
17	555	Standby Reservation Fee	REV							
18		Subtotal - Purchases		126,424,714	(725,733)	(46,851)				
19	500-557	Total Power Supply		126,424,714	(725,733)	(46,851)				
20										
21		**Transmission**								
22	560-573	Operation & Maintenance	TRAN1							
23	555	Transmission - G&T Charges	TRAN2	22,649,623						
24		Total Transmission		22,649,623						
25										
26		**Distribution**								
27	580	Oper. Super & Eng.	EX1							
28	581	Load Dispatch	EX1	1,410,722						
29	582	Oper. Station	SUB	631,828						
30	583	Oper. OH Line	PRI-OH	21,432						
31	584	Oper. UG Line	PRI-UG	703,799						
32	585	Oper. St. Lighting	STL							
33	586	Oper. Meters	MTR	1,949,081						
34	587	Oper. Cons. Install	ICON	50,520						
35	588	Oper. Misc. Oper.	EX1	1,849,603						
36	589	Rents	EX1							
37	590	Main. Super. & Eng.	EX2	4,204,506						
38	591	Main. Structure	SUB							
39	592	Main. Station	SUB	125,460						
40	593	Main. OH Line	PRI-OH	1,282,541						
41	594	Main. UG Line	PRI-UG							
42	595	Main. Line Transf.	TRF	12,832						
43	596	Main. St. Lighting	STL	491,419						491,419
44	597	Main. Meters	MTR							
45	598	Main. Misc. Dist.	EX2							
46	580-598	Subtotal		12,733,743						491,419

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
47		**Consumer Acct., Service & Sales**																
48		**Consumer Accounting**																
49	901	Supervision	CACC															
50	902	Meter Reading Expense	CACC	935,425													935,425	
51	903	Records & Collections	CACC	4,358,650													4,358,650	
52	904	Uncollectible Accounts	CACC	399,734													399,734	
53	905	Misc. Customer Account	CACC															
54		Subtotal		5,693,809													5,693,809	
55																		
56		**Consumer Service & Info.**																
57	907	Supervision	CS															
58	908	Customer Assistance	CS	2,247,863													2,247,863	
59	909	Info. & Instruction	CS	875,663													875,663	
60	910	Misc. Cust Serv. & Info	CS	281,773													281,773	
61		Subtotal		3,405,299													3,405,299	
62																		
63		**Sales**																
64	911	Supervision	SALES															
65	912	Demonstrating & Selling	SALES															
66	913	Advertising	SALES															
67	916	Misc. Sales	SALES															
68		Subtotal																
69																		
70		**Prorated Operating Expenses**																
71	920-	**Administrative & General**																
72	932	Power Supply	EX6-PS	1,170,247	860,025	317,373												
73		Transmission	EX6-TR															
74		Distribution	EX6-D	10,532,220					840,462		946,332	2,240,927	4,828	19,681		1,853,498	4,389,432	
75		Subtotal - A&G		11,702,467	860,025	317,373			840,462		946,332	2,240,927	4,828	19,681		1,853,498	4,389,432	
76																		
77	408	**Other Taxes**																
78		Power Supply	EX6-PS															
79		Transmission	EX6-TR															
80		Distribution	EX6-D															
81		Subtotal - Other Taxes																
82																		
83	421-	**Miscellaneous Expense**																
84	426,431	Power Supply	EX6-PS	51,654	37,961	14,009												
85		Transmission	EX6-TR															
86		Distribution	EX6-D	464,888					37,098		41,771	98,914	213	869		81,813	193,748	
87		Subtotal - Misc. Expense		516,542	37,961	14,009			37,098		41,771	98,914	213	869		81,813	193,748	

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
47		**Consumer Acct., Service & Sales**								
48		**Consumer Accounting**								
49	901	Supervision	CACC							
50	902	Meter Reading Expense	CACC	935,425						
51	903	Records & Collections	CACC	4,358,650						
52	904	Uncollectible Accounts	CACC	399,734						
53	905	Misc. Customer Account	CACC							
54		Subtotal		5,693,809						
55										
56		**Consumer Service & Info.**								
57	907	Supervision	CS							
58	908	Customer Assistance	CS	2,247,863						
59	909	Info. & Instruction	CS	875,663						
60	910	Misc. Cust Serv. & Info	CS	281,773						
61		Subtotal		3,405,299						
62										
63		**Sales**								
64	911	Supervision	SALES							
65	912	Demonstrating & Selling	SALES							
66	913	Advertising	SALES							
67	916	Misc. Sales	SALES							
68		Subtotal								
69										
70		**Prorated Operating Expenses**								
71	920-	**Administrative & General**								
72	932	Power Supply	EX6-PS	1,170,247	(6,718)	(434)				
73		Transmission	EX6-TR							
74		Distribution	EX6-D	10,532,220						237,062
75		Subtotal - A&G		11,702,467	(6,718)	(434)				237,062
76										
77	408	**Other Taxes**								
78		Power Supply	EX6-PS							
79		Transmission	EX6-TR							
80		Distribution	EX6-D							
81		Subtotal - Other Taxes								
82										
83	421-	**Miscellaneous Expense**								
84	426,431	Power Supply	EX6-PS	51,654	(297)	(19)				
85		Transmission	EX6-TR							
86		Distribution	EX6-D	464,888						10,464
87		Subtotal - Misc. Expense		516,542	(297)	(19)				10,464

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
88		**Fixed Charges**																
89	403-	**Depreciation**																
90	407	Power Supply	PROPLNT															
91		Transmission	TRNPLNT															
92		Distribution	DSTPLNT	10,408,894					1,516,978		4,657,498	2,519,423	226,938	925,038	78,444	177,014		
93		Subtotal - Depreciation		10,408,894					1,516,978		4,657,498	2,519,423	226,938	925,038	78,444	177,014		
94																		
95	408	**Property Taxes**																
96		Power Supply	PROPLNT															
97		Transmission	TRNPLNT															
98		Distribution	DSTPLNT	3,550,790					517,487		1,588,814	859,452	77,416	315,559	26,760	60,385		
99		Subtotal - Property Taxes		3,550,790					517,487		1,588,814	859,452	77,416	315,559	26,760	60,385		
100																		
101	427	**Interest-LT**																
102		Power Supply	PROPLNT															
103		Transmission	TRNPLNT															
104		Distribution	DSTPLNT	3,489,324					508,529		1,561,311	844,574	76,075	310,096	26,297	59,340		
105		Subtotal - Interest-LT		3,489,324					508,529		1,561,311	844,574	76,075	310,096	26,297	59,340		
106																		
107		**Required Margin**																
108		Power Supply	PROPLNT															
109		Transmission	TRNPLNT															
110		Distribution	DSTPLNT	6,495,238					946,607		2,906,318	1,572,142	141,611	577,231	48,950	110,458		
111		Subtotal - Required Margin		6,495,238					946,607		2,906,318	1,572,142	141,611	577,231	48,950	110,458		
112																		
113		**Summary of Revenue Requirements**																
114		Power Supply		127,646,615	93,808,633	34,618,033												
115		Transmission		22,649,623				22,649,623										
116		Distribution		56,774,205					6,109,403		13,663,749	12,780,779	537,091	2,189,270	180,451	6,184,731	13,682,287	
117		**Total Revenue Required**		207,070,443	93,808,633	34,618,033		22,649,623	6,109,403		13,663,749	12,780,779	537,091	2,189,270	180,451	6,184,731	13,682,287	

Classification of Revenue Requirements
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
88		**Fixed Charges**								
89	403-	**Depreciation**								
90	407	Power Supply	PROPLNT							
91		Transmission	TRNPLNT							
92		Distribution	DSTPLNT	10,408,894						307,560
93		Subtotal - Depreciation		10,408,894						307,560
94										
95	408	**Property Taxes**								
96		Power Supply	PROPLNT							
97		Transmission	TRNPLNT							
98		Distribution	DSTPLNT	3,550,790						104,918
99		Subtotal - Property Taxes		3,550,790						104,918
100										
101	427	**Interest-LT**								
102		Power Supply	PROPLNT							
103		Transmission	TRNPLNT							
104		Distribution	DSTPLNT	3,489,324						103,102
105		Subtotal - Interest-LT		3,489,324						103,102
106										
107		**Required Margin**								
108		Power Supply	PROPLNT							
109		Transmission	TRNPLNT							
110		Distribution	DSTPLNT	6,495,238						191,920
111		Subtotal - Required Margin		6,495,238						191,920
112										
113		**Summary of Revenue Requirements**								
114		Power Supply		127,646,615	(732,748)	(47,303)				
115		Transmission		22,649,623						
116		Distribution		56,774,205						1,446,444
117		**Total Revenue Required**		207,070,443	(732,748)	(47,303)				1,446,444

Summary of Classification Factors

Line					Power Supply		Transmission		Dist. Substation		Primary Line		Line Transf.		Second. & Serv.	Meter	Acct. & Serv.	
No.	Name	Description	Source	Total	Energy	Cap.	Energy	Capacity	Cap.	Cons.	Cap.	Cons.	Cap.	Cons.	Cons.	Cons.	Cons.	Revenue
		Classification Factor Data																
1	PROPLNT	Production Plant	Plant															
2	TRNPLNT	Transmission Plant	Plant															
3	DSTPLNT	Distribution Plant	Plant	157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	157,954,781					23,020,120		70,677,450	38,232,205	3,443,783	14,037,432	1,190,394	2,686,182		
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,356,660					631,828		542,430	233,321				1,949,081		
6	EX2	Assigned Dist. Main. Exp.	Rev Req	1,420,834					125,460		225,403	1,057,138	2,528	10,304				
7	EX3	Dist. Oper. & Main.	Rev Req	12,733,743					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224		
8	EX4	Assigned O & M Exp.	Rev Req	170,907,188	92,910,647	34,286,651		22,649,623	1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224	9,099,108	
9	EX4-PS	Power Supply	Rev Req	126,424,714	92,910,647	34,286,651												
10	EX4-TR	Transmission	Rev Req	22,649,623				22,649,623										
11	EX4-D	Distribution	Rev Req	21,832,851					1,742,242		1,961,706	4,645,347	10,009	40,797		3,842,224	9,099,108	
12	EX5	Rev. Req. Less Margin	Rev Req	200,575,205	93,808,633	34,618,033		22,649,623	5,162,796		10,757,431	11,208,637	395,479	1,612,039	131,501	6,074,272	13,682,287	
13	EX5-PS	Power Supply	Rev Req	127,646,615	93,808,633	34,618,033												
14	EX5-TR	Transmission	Rev Req	22,649,623				22,649,623										
15	EX5-D	Distribution	Rev Req	50,278,967					5,162,796		10,757,431	11,208,637	395,479	1,612,039	131,501	6,074,272	13,682,287	

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
		Classification Factor Data								
1	PROPLNT	Production Plant	Plant							
2	TRNPLNT	Transmission Plant	Plant							
3	DSTPLNT	Distribution Plant	Plant	157,954,781						4,667,216
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	157,954,781						4,667,216
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	3,356,660						
6	EX2	Assigned Dist. Main. Exp.	Rev Req	1,420,834						
7	EX3	Dist. Oper. & Main.	Rev Req	12,733,743						491,419
8	EX4	Assigned O & M Exp.	Rev Req	170,907,188	(725,733)	(46,851)				491,419
9	EX4-PS	Power Supply	Rev Req	126,424,714	(725,733)	(46,851)				
10	EX4-TR	Transmission	Rev Req	22,649,623						
11	EX4-D	Distribution	Rev Req	21,832,851						491,419
12	EX5	Rev. Req. Less Margin	Rev Req	200,575,205	(732,748)	(47,303)				1,254,524
13	EX5-PS	Power Supply	Rev Req	127,646,615	(732,748)	(47,303)				
14	EX5-TR	Transmission	Rev Req	22,649,623						
15	EX5-D	Distribution	Rev Req	50,278,967						1,254,524

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
16	**Classification Factors**																	
17	CACC	Consumer Accounting	Input	1.000000													1.000000	
18	CS	Customer Service	Input	1.000000													1.000000	
19	CS-PS	Cust. Service - Pwr. Supply	Input															
20	CS-TR	Cust. Service - Transmission	Input															
21	CS-D	Cust. Service - Distribution	Input															
22	SALES	Sales	Input															
23	SALES-PS	Sales - Power Supply	Input															
24	SALES-TR	Sales - Transmission	Input															
25	SALES-D	Sales - Distribution	Input															
26	PROPLNT	Production Plant	Plant															
27	TRNPLNT	Transmission Plant	Plant															
28	DSTPLNT	Distribution Plant	Plant	1.000000					0.145739		0.447454	0.242045	0.021802	0.088870	0.007536	0.017006		
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000					0.145739		0.447454	0.242045	0.021802	0.088870	0.007536	0.017006		
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000					0.188231		0.161598	0.069510				0.580661		
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000					0.088300		0.158642	0.744027	0.001779	0.007252				
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000					0.136821		0.154056	0.364806	0.000786	0.003204		0.301736		
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	0.543632	0.200616		0.132526	0.010194		0.011478	0.027181	0.000059	0.000239		0.022481	0.053240	
34	EX4-PS	Power Supply	Rev Req	0.739727	0.543632	0.200616												
35	EX4-TR	Transmission	Rev Req	0.132526				0.132526										
36	EX4-D	Distribution	Rev Req	0.127747					0.010194		0.011478	0.027181	0.000059	0.000239		0.022481	0.053240	
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	0.467698	0.172594		0.112923	0.025740		0.053633	0.055882	0.001972	0.008037	0.000656	0.030284	0.068215	
38	EX5-PS	Power Supply	Rev Req	0.636403	0.467698	0.172594												
39	EX5-TR	Transmission	Rev Req	0.112923				0.112923										
40	EX5-D	Distribution	Rev Req	0.250674					0.025740		0.053633	0.055882	0.001972	0.008037	0.000656	0.030284	0.068215	
41	EX6	A&G Classification	Input	1.000000	0.073491	0.027120			0.071819		0.080866	0.191492	0.000413	0.001682		0.158385	0.375086	
42	EX6-PS	Power Supply	Input	0.100000	0.073491	0.027120												
43	EX6-TR	Transmission	Input															
44	EX6-D	Distribution	Input	0.900000					0.071819		0.080866	0.191492	0.000413	0.001682		0.158385	0.375086	
45	FUEL	Fuel	Input															
46	ICON	Install Cons. Prem.	Input	1.000000							0.175747	0.824253						
47	LAND	Land & Land Rights	Input	1.000000					1.00000									
48	LICON	Leased Property	Input	1.000000							0.175747	0.824253						
49	MTR	Meters	Input	1.000000												1.000000		
50	POLES	Poles, Towers, and Fixtures	1.0000								0.439954	0.560046						
51	PRI-OH	Primary Line-Overhead	Input	1.000000							0.175747	0.824253						
52	PRI-UG	Primary Line-Underground	1.0000								0.752750	0.247250						
53	PROD1	Production Plant	Input															
54	PROD2	Production O & M	Input															
55	PURTR-1	Trans. Capacity	Input	1.000000				1.000000										
56	PURTR-2	Trans. Energy	Input	1.000000	1.000000													
57	PURKW-1	Purchased Power Capacity	Input	1.000000		1.000000												
58	PURKW-2	Summer	Input	1.000000		1.000000												
59	PURKW-3	Winter	Input	1.000000		1.000000												
60	PURKW-4	Other	Input	1.000000		1.000000												
61	PURKWH-1	Purchased Power Energy	Input	1.000000	1.000000													
62	PURKWH-2	On-Peak	Input	1.000000	1.000000													
63	PURKWH-3	Off-Peak	Input	1.000000	1.000000													
62	SERV	Services	Input	1.000000											1.000000			
63	STL	Street Lighting	Input															
64	SUB	Substation	Input	1.000000					1.000000									
65	TRAN1	Transmission Plant	Input	1.000000				1.000000										
66	TRAN2	Transmission Purchases	Input	1.000000				1.000000										
67	TRF	Line Transf.	Input	1.000000									0.196999	0.803001				

Summary of Classification Factors

Line No.	Name	Description	Source	Total	Resid. & Farm Direct	Small General Service Direct	Irrigation Direct	General Service Direct	C&I Interruptible Direct	Lighting Direct
16	**Classification Factors**									
17	CACC	Consumer Accounting	Input	1.000000						
18	CS	Customer Service	Input	1.000000						
19	CS-PS	Cust. Service - Pwr. Supply	Input							
20	CS-TR	Cust. Service - Transmission	Input							
21	CS-D	Cust. Service - Distribution	Input							
22	SALES	Sales	Input							
23	SALES-PS	Sales - Power Supply	Input							
24	SALES-TR	Sales - Transmission	Input							
25	SALES-D	Sales - Distribution	Input							
26	PROPLNT	Production Plant	Plant							
27	TRNPLNT	Transmission Plant	Plant							
28	DSTPLNT	Distribution Plant	Plant	1.000000						0.029548
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000						0.029548
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000						
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000						
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000						0.038592
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	(0.004246)	(0.000274)				0.002875
34	EX4-PS	Power Supply	Rev Req	0.739727	(0.004246)	(0.000274)				
35	EX4-TR	Transmission	Rev Req	0.132526						
36	EX4-D	Distribution	Rev Req	0.127747						0.002875
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	(0.003653)	(0.000236)				0.006255
38	EX5-PS	Power Supply	Rev Req	0.636403	(0.003653)	(0.000236)				
39	EX5-TR	Transmission	Rev Req	0.112923						
40	EX5-D	Distribution	Rev Req	0.250674						0.006255
41	EX6	A&G Classification	Input	1.000000	(0.000574)	(0.000037)				0.020257
42	EX6-PS	Power Supply	Input	0.100000	(0.000574)	(0.000037)				
43	EX6-TR	Transmission	Input							
44	EX6-D	Distribution	Input	0.900000						0.020257
45	FUEL	Fuel	Input							
46	ICON	Install Cons. Prem.	Input	1.000000						
47	LAND	Land & Land Rights	Input	1.000000						
48	LICON	Leased Property	Input	1.000000						
49	MTR	Meters	Input	1.000000						
50	POLES	Poles, Towers, and Fixtures	1.0000							
51	PRI-OH	Primary Line-Overhead	Input	1.000000						
52	PRI-UG	Primary Line-Underground	1.0000							
53	PROD1	Production Plant	Input							
54	PROD2	Production O & M	Input							
55	PURTR-1	Trans. Capacity	Input	1.000000						
56	PURTR-2	Trans. Energy	Input	1.000000						
57	PURKW-1	Purchased Power Capacity	Input	1.000000						
58	PURKW-2	Summer	Input	1.000000						
59	PURKW-3	Winter	Input	1.000000						
60	PURKW-4	Other	Input	1.000000						
61	PURKWH-1	Purchased Power Energy	Input	1.000000						
62	PURKWH-2	On-Peak	Input	1.000000						
63	PURKWH-3	Off-Peak	Input	1.000000						
62	SERV	Services	Input	1.000000						
63	STL	Street Lighting	Input							
64	SUB	Substation	Input	1.000000						
65	TRAN1	Transmission Plant	Input	1.000000						
66	TRAN2	Transmission Purchases	Input	1.000000						
67	TRF	Line Transf.	Input	1.000000						

Summary of Allocation of Revenue Requirements to Rate Classes

Line No.	Cost Classification		Alloc. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Power Supply**									
2	**Wholesale Power**									
3	Direct Assigned Charges (Credits)		Direct							
4	Demand Related		D7							
5	Demand Related - Summer		D4	17,112,830	10,370,341	464,867	21,695	6,179,315	76,613	
6	Demand Related - Winter		D5	8,390,047	5,458,423	302,784		2,488,808	36,721	103,311
7	Demand Related - Other		D6	8,011,190	4,952,367	264,721	3,164	2,702,767	36,516	51,656
8	Subtotal - Demand			33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
9	Energy Charges - Critical Peak		E2							
10	Energy Related - On-Peak		E3	36,393,097	17,333,391	879,140	164,592	9,570,234	8,407,488	38,252
11	Energy Related - Off-Peak		E4	56,517,550	26,723,916	1,355,423	253,762	14,754,997	12,962,322	467,130
12	Subtotal - Energy			92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
13	Revenue Related		R2							
14	Subtotal - Wholesale			126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
15	**Allocated Overhead & Margin**									
16	Direct Related		Direct							
17	Revenue Related		R2							
18	Demand Related		D7	328,991	198,146	10,188	183	105,776	12,878	1,819
19	Energy Related		E1	892,910	420,872	21,278	4,042	235,006	206,454	5,257
20	Subtotal - Allocated			1,221,901	619,019	31,466	4,225	340,782	219,332	7,076
21	Subtotal - Power Supply			127,646,615	65,457,456	3,298,400	447,438	36,036,904	21,738,992	667,425
22										
23	**Transmission**									
24	Direct Assigned		Direct							
25	Demand Related		D7	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
26	Energy Related		E1							
27	Subtotal--Transmission			22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
28	**Allocated Overhead & Margin**									
29	Direct Related		Direct							
30	Revenue Related		R2							
31	Demand Related		D7							
32	Energy Related		E1							
33	Subtotal - Allocated									
34	Subtotal - Transmission			22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
35										
36	**Distribution**									
37	Power Supply	-Energy	E1							
38	Dist. Sub.	-Capacity	D9	6,109,403	3,010,588	149,743	47,121	1,598,656	1,263,802	39,493
39	Dist. Sub.	-Consumer	C2							
40	Primary Line	-Capacity	D9	13,663,749	6,733,215	334,901	105,386	3,575,413	2,826,507	88,326
41	Primary Line	-Consumer	C2	12,780,779	11,552,938	610,737	67,936	463,412	47,096	38,660
42	Line Transf.	-Capacity	D1	537,091	369,821	16,955	10,460	87,871	50,629	1,355
43	Line Transf.	-Consumer	C3	2,189,270	1,946,450	115,497	14,312	96,436	10,063	6,513
44	Sec. & Serv.	-Consumer	C4	180,451	165,079	7,965	798	5,512	544	552
45	Meter	-Consumer	C5	6,184,731	5,150,000	311,923	58,073	449,082	198,419	17,234
46	Acct. & Serv.	-Consumer	C6	13,682,287	11,393,185	690,057	128,473	993,491	438,957	38,125
47	Revenue Related	-Revenue	R2							
48	Direct Assigned		Direct	1,446,444						1,446,444
49	Subtotal - Distribution			56,774,205	40,321,277	2,237,776	432,558	7,269,873	4,836,017	1,676,703
50	**Total**			207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Allocation of Net Plant in Service To Rate Classes

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1		**Net Intangible Plant**								
2	301	Organization	PLNT							
3	302	Franchises and consents	PLNT							
4	303	Miscellaneous intangible plant	PLNT							
5	301-303	Subtotal	PLNT							
6										
7		**Net Production Plant**								
8	310-346	Production Plant	PROD1							
9										
10		**Net Transmission Plant**								
11	350-359	Transmission Plant	TRAN1							
12										
13		**Net Distribution Plant**								
14	360	Land	LAND	4,163,712	2,517,895	129,805	2,300	1,329,041	161,813	22,858
15	361	Structures	SUB							
16	362	Station	SUB	18,856,408	11,402,915	587,852	10,416	6,018,896	732,812	103,517
17	363	Battery	SUB							
18	364	Poles, towers	PRI	10,796,888	7,806,614	405,374	68,778	1,462,221	1,004,903	48,997
19	365	OH Cond	PRI	13,738,437	11,425,872	600,301	78,815	1,042,393	541,194	49,861
20	366	UG Conduit	PRI							
21	367	UG Cond	PRI	84,374,330	50,155,173	2,553,592	600,753	17,375,897	13,215,247	473,668
22	368	Transf	TRF	17,481,215	14,851,750	849,266	158,835	1,181,760	389,152	50,453
23	369	Services	SERV	1,190,394	1,088,990	52,546	5,261	36,362	3,591	3,644
24	370	Meters	MTR	2,686,182	2,236,773	135,476	25,222	195,048	86,178	7,485
25	371	Cons Premise	ICON	123,745						123,745
26	372	Leased Prop	LICON							
27	373	St. Light	STL	4,543,471						4,543,471
28	360-373	Subtotal		157,954,781	101,485,981	5,314,211	950,381	28,641,619	16,134,891	5,427,699
29										
30		**Net General Plant**								
31	389	Land & Land Rights	PLNT	102,278	65,714	3,441	615	18,546	10,448	3,515
32	390	Structures and Improve.	PLNT	4,601,923	2,956,737	154,827	27,689	834,457	470,081	158,133
33	391	Office Furniture & Equip.	PLNT	5,056,678	3,248,917	170,126	30,425	916,917	516,534	173,759
34	392	Transportation & Equipment	PLNT	918,591	590,195	30,905	5,527	166,566	93,833	31,565
35	393	Stores Equipment	PLNT	18,982	12,196	639	114	3,442	1,939	652
36	394	Tool, Shop & Garage Equip.	PLNT	156,304	100,425	5,259	940	28,342	15,966	5,371
37	395	Laboratory Equipment	PLNT	209,246	134,441	7,040	1,259	37,942	21,374	7,190
38	396	Power Operated Equipment	PLNT	3,930,565	2,525,389	132,239	23,649	712,721	401,502	135,063
39	397	Communication Equipment	PLNT	345,799	222,176	11,634	2,081	62,703	35,323	11,882
40	398	Miscellaneous Equipment	PLNT	84,672	54,402	2,849	509	15,353	8,649	2,910
41	399	Other tangible property	PLNT	633,349	406,927	21,308	3,811	114,844	64,696	21,763
42	389-399	Subtotal		16,058,389	10,317,518	540,266	96,620	2,911,835	1,640,345	551,804
43										
44		**Total Net Plant in Service**		174,013,170	111,803,499	5,854,477	1,047,001	31,553,453	17,775,236	5,979,503

Allocation of Revenue Requirements to Rate Classes

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1		**Power Supply**								
2		**Production**								
3	500-557	Fuel	FUEL							
4	500-557	Non-Fuel O&M - Demand	PROD1							
5	500-557	Non-Fuel O&M - Energy	PROD1							
6		Subtotal - Production								
7		**Purchases**								
8	555	Direct Assign. Chgs (Cr.)								
9	555	Substation Charges	PURSUB							
10	555	Demand Charges	PURKW-1							
11	555	Summer	PURKW-2	17,112,830	10,370,341	464,867	21,695	6,179,315	76,613	
12	555	Winter	PURKW-3	8,390,047	5,458,423	302,784		2,488,808	36,721	103,311
13	555	Other	PURKW-4	8,011,190	4,952,367	264,721	3,164	2,702,767	36,516	51,656
14		Total Demand		33,514,067	20,781,131	1,032,371	24,859	11,370,890	149,849	154,967
15	555	Energy Charges - Critical Peak	PURKWH-1							
16	555	Energy Charges - On-Peak	PURKWH-2	36,393,097	17,333,391	879,140	164,592	9,570,234	8,407,488	38,252
17	555	Energy Charges - Off-Peak	PURKWH-3	56,517,550	26,723,916	1,355,423	253,762	14,754,997	12,962,322	467,130
18		Total Energy		92,910,647	44,057,307	2,234,564	418,354	24,325,231	21,369,810	505,382
19	555	Standby Reservation Fee	REVENUE							
20		Subtotal - Purchases		126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
21	500-557	Total Power Supply		126,424,714	64,838,438	3,266,934	443,213	35,696,121	21,519,659	660,349
22		**Transmission**								
23	560-573	Operation & Maintenance	TRAN1							
24	555	Transmission - G&T Charges	TRAN2	22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
25		Total Transmission		22,649,623	13,696,762	706,106	12,511	7,229,676	880,227	124,341
26		**Distribution**								
27	580	Oper. Super & Eng.	EX1							
28	581	Load Dispatch	EX1	1,410,722	1,013,935	58,095	12,019	192,173	128,730	5,769
29	582	Oper. Station	SUB	631,828	311,352	15,486	4,873	165,331	130,701	4,084
30	583	Oper. OH Line	PRI-OH	21,432	17,824	936	123	1,626	844	78
31	584	Oper. UG Line	PRI-UG	703,799	418,364	21,300	5,011	144,939	110,233	3,951
32	585	Oper. St. Lighting	STL							
33	586	Oper. Meters	MTR	1,949,081	1,622,992	98,301	18,301	141,526	62,531	5,431
34	587	Oper. Cons. Install	ICON	50,520	42,016	2,207	290	3,833	1,990	183
35	588	Oper. Misc. Oper.	EX1	1,849,603	1,329,374	76,169	15,758	251,959	168,779	7,564
36	589	Rents	EX1							
37	590	Main. Super. & Eng.	EX2	4,204,506	3,371,633	176,779	24,981	387,678	227,151	16,284
38	591	Main. Structure	SUB							
39	592	Main. Station	SUB	125,460	61,824	3,075	968	32,829	25,953	811
40	593	Main. OH Line	PRI-OH	1,282,541	1,066,654	56,041	7,358	97,312	50,523	4,655
41	594	Main. UG Line	PRI-UG							
42	595	Main. Line Transf.	TRF	12,832	10,902	623	117	867	286	37
43	596	Main. St. Lighting	STL	491,419						491,419
44	597	Main. Meters	MTR							
45	598	Main. Misc. Dist.	EX2							
46	580-598	Subtotal		12,733,743	9,266,869	509,013	89,799	1,420,075	907,720	540,267

Allocation of Revenue Requirements to Rate Classes
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
47		**Consumer Acct., Service & Sales**								
48		**Consumer Accounting**								
49	901	Supervision	CACC							
50	902	Meter Reading Expense	CACC	935,425	778,924	47,177	8,783	67,923	30,010	2,607
51	903	Records & Collections	CACC	4,358,650	3,629,430	219,825	40,926	316,488	139,835	12,145
52	904	Uncollectible Accounts	CACC	399,734	332,857	20,160	3,753	29,025	12,824	1,114
53	905	Misc. Customer Account	CACC							
54		Subtotal		5,693,809	4,741,212	287,163	53,463	413,436	182,669	15,866
55		**Consumer Service & Info.**								
56	907	Supervision	CS							
57	908	Customer Assistance	CS	2,247,863	1,871,787	113,369	21,107	163,221	72,116	6,264
58	909	Info. & Instruction	CS	875,663	729,161	44,163	8,222	63,583	28,093	2,440
59	910	Misc. Cust Serv. & Info	CS	281,773	234,631	14,211	2,646	20,460	9,040	785
60		Subtotal		3,405,299	2,835,579	171,744	31,975	247,264	109,249	9,489
61		**Sales**								
62	911	Supervision	SALES							
63	912	Demonstrating & Selling	SALES							
64	913	Advertising	SALES							
65	916	Misc. Sales	SALES							
66		Subtotal								
67		**Prorated Operating Expenses**								
68		**Administrative & General**								
69	920	Administrative & General		6,994,984						
70	921	Office Supplies & Expenses		1,400,794						
71	922	Admin. Expenses Transferred								
72	923	Outside Services Employed		468,099						
73	924	Property Insurance		72,601						
74	925	Injuries & Damages		3,441						
75	926	Employee Pensions & Benefits		1,665,361						
76	927	Franchise Requirements								
77	928	Regulatory Commission Exp.		419,597						
78	929	Duplicate Charges								
79	930.1	General Advertising								
80	930.2	Misc.		677,590						
81	931	Rents								
82	935	Maint. of General Plant								
83		Accounts 920-935		11,702,467						
84		Power Supply	EX6-PS	1,170,247	592,851	30,136	4,046	326,376	210,061	6,777
85		Transmission	EX6-TR							
86		Distribution	EX6-D	10,532,220	8,125,422	466,927	84,535	1,003,771	578,709	272,857
87		Subtotal - A&G		11,702,467	8,718,273	497,063	88,581	1,330,147	788,769	279,634

Allocation of Revenue Requirements to Rate Classes
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
88	408	**Other Taxes**								
89		Power Supply	EX6-PS							
90		Transmission	EX6-TR							
91		Distribution	EX6-D							
92		Subtotal - Other Taxes								
93	421-	**Miscellaneous Expense**								
94	426,431	Power Supply	EX6-PS	51,654	26,168	1,330	179	14,406	9,272	299
95		Transmission	EX6-TR							
96		Distribution	EX6-D	464,888	358,653	20,610	3,731	44,306	25,544	12,044
97		Subtotal - Misc. Expense		516,542	384,821	21,940	3,910	58,712	34,816	12,343
98		**Fixed Charges**								
99	403-	**Depreciation**								
100	407	Power Supply	PROPLNT							
101		Transmission	TRNPLNT							
102		Distribution	DSTPLNT	10,408,894	6,517,900	340,085	73,490	1,800,160	1,318,107	359,153
103		Subtotal - Depreciation		10,408,894	6,517,900	340,085	73,490	1,800,160	1,318,107	359,153
104	408	**Property Taxes**								
105		Power Supply	PROPLNT							
106		Transmission	TRNPLNT							
107		Distribution	DSTPLNT	3,550,790	2,223,454	116,013	25,070	614,089	449,646	122,518
108		Subtotal - Property Taxes		3,550,790	2,223,454	116,013	25,070	614,089	449,646	122,518
109										
110		Total Oper. Expenses		174,436,258	99,526,544	5,209,956	809,501	41,580,003	25,310,637	1,999,617
111										
112	427	**Interest-LT**								
113		Power Supply	PROPLNT							
114		Transmission	TRNPLNT							
115		Distribution	DSTPLNT	3,489,324	2,184,965	114,005	24,636	603,459	441,863	120,397
116		Subtotal - Interest-LT		3,489,324	2,184,965	114,005	24,636	603,459	441,863	120,397
117		**Required Margin**								
118		Power Supply	PROPLNT							
119		Transmission	TRNPLNT							
120		Distribution	DSTPLNT	6,495,238	4,067,225	212,216	45,859	1,123,315	822,510	224,114
121		Subtotal - Required Margin		6,495,238	4,067,225	212,216	45,859	1,123,315	822,510	224,114
122		**Summary of Revenue Requirements**								
123		Total Rev. Req.		207,070,443	119,475,495	6,242,283	892,507	50,536,453	27,455,236	2,468,469

Rate Class Weighting Factors

I. Three Phase Vs. Single Phase Class Weighting Factors

A. Investment to Serve 3Ø vs. 1Ø Consumers (use replacement cost)

1. Meters	1Ø		3Ø		Wtd.
a. Resid.& Farm	$88.39	100%		0%	$88.39
b. Small General Service	$88.39	65%	$181.86	35%	$121.10
c. Irrigation	$191.86	10%	$261.86	90%	$254.86
d. General Service		18%	$341.86	82%	$280.33
e. C&I Interruptible		0%	$1,302.86	100%	$1,302.86
2 Service [1]	$481		$694		
3. Transformer [2]	$1,718		$2,751		
4. Primary Line [3]	$1,151		$1,787		

B. Weighting Factors for Relative 3Ø Class Investment Costs

1. Meters					
a. Resid.& Farm	$88	÷	$88	=	1.00
b. Small General Service	$121	÷	$88	=	1.37
c. Irrigation	$255	÷	$88	=	2.88
d. General Service	$280	÷	$88	=	3.17
e. C&I Interruptible	$1,303	÷	$88	=	14.74
2 Service	$2,330	÷	$1,847	=	1.26
3. Transformer	$8,582	÷	$4,339	=	1.98
4. Primary Line	$6,393	÷	$4,099	=	1.56

[1] Assume a typical installation of 80 feet of 1/0 triplex (or quadriplex), pole and miscellaneous materials to estimate the difference between a 1Ø and 3Ø installation.

[2] Use the cost difference between 1-75 kVA transformer and 3-25 kVA transformers as representative of the difference between a 1Ø versus a 3Ø transformer installation.

[3] Assume a typical installation of 150 feet of 1/0 ACSR to estimate the difference in primary line between a 1Ø and 3Ø installation.

Analysis of Class Load Characteristics

Line No.	Description	Units	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**Class Billing Determinants**								
2	No. of Cons.	cons.	124,847	100,235	4,431	392	2,756	262	16,771
3	Energy Sales -- All	MWh	1,769,404	838,684	42,538	7,964	463,060	406,800	10,359
4	Energy Sales -- On-Peak	MWh	591,321	281,636	14,284	2,674	155,499	136,606	622
5	Energy Sales -- Off-Peak	MWh	1,178,083	557,048	28,253	5,290	307,561	270,194	9,737
6	Billing Demand	kW-mo.	2,496,047			76,255	1,449,303	970,490	
7									
8	**Demand Estimate**								
9	Non-Coincidental Demand of								
10	Individual Cons.	kW	1,122,260.0	772,748	35,427	21,856	183,608	105,789	2,832
11	Non-Coincidental Class Demand	kW	387,770.7	201,097	9,755	4,702	101,451	67,934	2,832
12	Coincidental Summer Demand	kW	326,853.1	202,779	9,352	396	112,926	1,400	
13	Coincidental Winter Demand	kW	229,990.6	149,628	8,300		68,224	1,007	2,832
14	Coincidental Other Demand	kW	219,605.0	135,756	7,257	87	74,089	1,001	1,416
15	Coincidental Class Demand-Transm.	kW	257,935.3	155,980	8,041	142	82,332	10,024	1,416
16	Base Rated Substation Capacity	kVA	632,500.0						

Estimate of Class Demands

I. Residential & Farm (31,32,53)

A. Demand Per Consumer Calculation

	Summer [1]	Winter [1]	Other [1]	Avg.
Energy usage/Month (kWh/cons/mo)	900	727	643	722
Estimated fully diversified demand per consumer (kW/cons.) [2]	2.44	2.02	1.81	2.01

B. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

"A" Factor [3] = (1 - 0.4 + 0.4 (1² + 40)^1/2) = 3.1612

Total kW = 100,235 Cons. x 3.1612 x 2.44 = 772,748

C. Non-Coincidental Class Demand (Average Monthly)

"A" Factor [3] = (1 - (0.4 x 100,235) + 0.4(100,235² + 40)^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.01 = 201,097

D. Non-Coincidental Class Demand (Summer)

"A" Factor [3] = (1 - (0.4 x 100,235) + 0.4(100,235² + 40)^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.44 = 244,463

E. Non-Coincidental Class Demand (Winter)

(1 - "A" Factor [3] = (1 - (0.4 x 100,235) + 0.4(100,235² + 40)^1/2) = 1.0001

Total kW = 100,235 Cons. x 1.0001 x 2.02 = 202,394

---

1 GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

2 The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

3 The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{1/2})$$

Estimate of Class Demands
(Continued)

I. Residential & Farm (31,32,53) (Continued)

F. Non-Coincidental Class Demand (Other)

"A" Factor [3]	=	(1 - (0.4 x 100,235) + 0.4(100,235² + 40)^1/2)						=	1.0001
Total kW	=	100,235	Cons.	x	1.0001	x	1.81	=	181,664

G. Assigned Coincidental Demand Responsibility -- Summer

kW = 202,779 [4]

H. Assigned Coincidental Demand Responsibility -- Winter

kW = 149,628 [4]

I. Assigned Coincidental Demand Responsibility -- Other

kW = 135,756 [4]

J. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 155,980 [4]

---

[1] GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

[2] The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

[3] The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{1/2})$$

[4] See pages 39 and 40.

Estimate of Class Demands
(Continued)

II. Small General Service (41)

A. Demand Per Consumer Calculation

	Summer [1]	Winter [1]	Other [1]	Avg.
Energy usage/Month (kWh/cons/mo)	852	938	783	800
Estimated fully diversified demand per consumer (kW/cons.) [2]	2.32	2.53	2.16	2.20

B. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

"A" Factor [3]	=	(1 - 0.4 + 0.4 (1² + 40)^1/2)						=	3.1612
Total kW	=	4,431	Cons.	x	3.1612	x	2.53	=	35,427

C. Non-Coincidental Class Demand (Average Monthly)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)						=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x	2.20	=	9,755

D. Non-Coincidental Class Demand (Summer)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)						=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x	2.32	=	10,319

E. Non-Coincidental Class Demand (Winter)

"A" Factor [3]	=	(1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2)						=	1.0018
Total kW	=	4,431	Cons.	x	1.0018	x	2.53	=	11,227

---

[1] GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

[2] The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

[3] The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{½})$$

Estimate of Class Demands
(Continued)

II. Small General Service (41) (Continued)

F. Non-Coincidental Class Demand (Other)

"A" Factor [3] = (1 - (0.4 x 4,431) + 0.4(4,431² + 40)^1/2) = 1.0018

Total kW = 4,431 Cons. x 1.0018 x 2.16 = 9,566

G. Assigned Coincidental Demand Responsibility -- Summer

kW = 9,352 [4]

H. Assigned Coincidental Demand Responsibility -- Winter

kW = 8,300 [4]

I. Assigned Coincidental Demand Responsibility -- Other

kW = 7,257 [4]

J. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 8,041 [4]

---

[1] GRE defines summer months to be June, July and August -- Winter months to be January, February, and December.

[2] The fully diversified demand per consumer is based on the "B" factor formula contained in the RUS Demand Tables (Bulletin 45-2), adjusted such that the total calculated demand at the substation equals the metered demand.

$$\text{kW/cons.} = .005925(\text{kWh})^{.885}$$

[3] The "A" Factor from the RUS Demand Table reflects interclass diversity.

$$\text{"A"} = (1 - .4C + .4(C^2 + 40)^{½})$$

[4] See pages 39 and 40.

Estimate of Class Demands
(Continued)

III. Irrigation (36)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

21,856 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 76,255 kW.

2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:

   7,963,872 kWh/(76,255 kW x 730 hr.) = 14.3%

3. The coincidence factor is estimated from Bary curves to be 74%.

4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:

   (76,255 kW / 12 mo.) x 0.74 = 4,702 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 15,828 kW.

2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:

   2,312,050 kWh/(15,828 kW x 730 hr.) = 20.0%

3. The coincidence factor is estimated from Bary curves to be 79%.

4. The non-coincidental (system basis) summer demand of the class is estimated to be:

   15,828 kW x 0.79 = 12,504 kW

Estimate of Class Demands
(Continued)

III. Irrigation (36) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 159 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   11,999 kWh/(159 kW x 730 hr.) = 0.0%

3. The coincidence factor is estimated from Bary curves to be 0%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   159 kW x 0.00 = 0 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the other months non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 4,716 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   165,287 kWh/(4,716 kW x 730 hr.) = 4.8%

3. The coincidence factor is estimated from Bary curves to be 58%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   4,716 kW x 0.58 = 2,735 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 396 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 0 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 87 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 142 [1]

[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

IV. General Service (46)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

183,608 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 1,449,303 kW.

2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:
463,059,984 kWh/(1,449,303 kW x 730 hr.) = 43.8%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:
(1,449,303 kW / 12 mo.) x 0.84 = 101,451 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 139,671 kW.

2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:
50,334,827 kWh/(139,671 kW x 730 hr.) = 49.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) summer demand of the class is estimated to be:
139,671 kW x 0.84 = 117,323 kW

Estimate of Class Demands
(Continued)

IV. General Service (46) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 109,861 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   42,032,747 kWh/(109,861 kW x 730 hr.) = 52.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   109,861 kW x 0.84 = 92,283 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the Other non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 116,785 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   39,942,113 kWh/(116,785 kW x 730 hr.) = 46.9%

3. The coincidence factor is estimated from Bary curves to be 83%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   116,785 kW x 0.83 = 96,931 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 112,926 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 68,224 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 74,089 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 82,332 [1]

[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

V. General Service Peak Alert (70,71)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

The sum of the peak annual non-coincidental demand of the consumers in this class is determined as follows:

105,789 kW

B. Non-Coincidental Class Demand (Average Monthly)

1. The sum of the monthly non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 970,490 kW.

2. The average nondiversified (class basis) monthly load factor of the class is calculated as follows:
   406,800,000 kWh/(970,490 kW x 730 hr.) = 57.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) average monthly demand of the class is estimated to be:
   (970,490 kW / 12 mo.) x 0.84 = 67,934 kW

C. Non-Coincidental Class Demand (Summer)

1. The sum of the summer non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 93,162 kW.

2. The average nondiversified (class basis) summer load factor of the class is calculated as follows:
   38,279,750 kWh/(93,162 kW x 730 hr.) = 56.3%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) summer demand of the class is estimated to be:
   93,162 kW x 0.84 = 78,256 kW

Estimate of Class Demands
(Continued)

V. General Service Peak Alert (70,71) (Continued)

D. Non-Coincidental Class Demand (Winter)

1. The sum of the winter non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 68,418 kW.

2. The average nondiversified (class basis) winter load factor of the class is calculated as follows:

   31,189,530 kWh/(68,418 kW x 730 hr.) = 62.4%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) winter demand of the class is estimated to be:

   68,418 kW x 0.84 = 57,471 kW

E. Non-Coincidental Class Demand (Other)

1. The sum of the Other non-coincidental (class basis) demands of individual consumers in this class is determined from billing records (adjusted to Test Year conditions) to be 80,958 kW.

2. The average nondiversified (class basis) other load factor of the class is calculated as follows:

   33,065,360 kWh/(80,958 kW x 730 hr.) = 55.9%

3. The coincidence factor is estimated from Bary curves to be 84%.

4. The non-coincidental (system basis) other demand of the class is estimated to be:

   80,958 kW x 0.84 = 68,005 kW

F. Assigned Coincidental Demand Responsibility -- Summer

   kW = 1,400 [1]

G. Assigned Coincidental Demand Responsibility -- Winter

   kW = 1,007 [1]

H. Assigned Coincidental Demand Responsibility -- Other

   kW = 1,001 [1]

I. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

   kW = 1,102 [1]

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[1] See pages 39 and 40.

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

	Power Required Per Light			No. of	
Size & Type	**Lamp**	**Ballast**	**Total**	**Lights**	**Total**
	(kW)	(kW)	(kW)		(kW)
Security Lighting (Schedule 44)					
175 W MV	0.175	0.035	0.210	0	0
100 W HPS	0.100	0.035	0.135	819	111
150 W HPS	0.150	0.050	0.200	4	1
250 W HPS	0.250	0.060	0.310	8	2
				831	114
Street Lighting (Schedule 44-2))					
(DEA Owned Equipment)					
175 W MV	0.175	0.035	0.210	0	0
250 W MV	0.250	0.050	0.300	3	1
400 W MV	0.400	0.050	0.450	0	0
100 W HPS	0.100	0.035	0.135	38	5
150 W HPS	0.150	0.050	0.200	646	129
250 W HPS	0.250	0.060	0.310	1,597	495
400 W HPS	0.400	0.075	0.475	1	0
				2,285	631
Street Lighting (Schedule 44-1)					
(Cons. Owned Equipment)					
175 W MV	0.175	0.035	0.210	0	0
250 W MV	0.250	0.050	0.300	0	0
400 W MV	0.400	0.050	0.450	0	0
100 W HPS	0.100	0.035	0.135	0	0
150 W HPS	0.150	0.050	0.200	101	20
200 W HPS	0.200	0.055	0.255	101	26
250 W HPS	0.250	0.060	0.310	272	84
400 W HPS	0.400	0.075	0.475	13	6
				487	136
Custom Resid. Lighting(Schedule 44-3)					
(DEA Owned contrib. by Cons.)					
175 W MV	0.175	0.035	0.210	0	0
50 W HPS	0.050	0.020	0.070	81	6
100 W HPS	0.100	0.035	0.135	8,416	1,136
150 W HPS	0.150	0.050	0.200	3,732	746
250 W HPS	0.250	0.060	0.310	4	1
				12,233	1,889
LED Security Lighting (44-4)					
LED, >4,500 Lumens			0.048	338	16

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting (Continued)

A. Sum of Non-Coincidental Demands of Individual Consumers (Annual Peak)

Size & Type	Power Required Per Light: Lamp	Ballast	Total	No. of Lights	Total
LED Street Lighting Member Owned(44-5)					
A (40-80 watts)			0.060	0	0
B (81-150 watts)			0.115	0	0
C (151-250 watts)			0.200	11	2
D (251-350 watts)			0.300	0	0
E (351-450 watts)			0.400	0	0
				11	2
LED Street Lighting (44-6)					
Standard					
>5,200 L, Coach (Post)			0.075	121	9
>5,200 L, Acorn (Post)			0.060	48	3
>7,000 L, Cobra (Mast)			0.066	91	6
>11,500 L, Shoebox			0.109	151	16
Basic					
>5,200 L, Coach (Post)			0.075	41	3
>5,200 L, Acorn (Post)			0.060	0	0
>7,000 L, Cobra (Mast)			0.066	53	3
>11,500 L, Shoebox			0.109	16	2
				521	43

The sum of the non-coincidental demands of individual lights is estimated as: 2,832 kW

Estimate of Class Demands
(Continued)

VI. Street and Security Lighting

B. Non-Coincidental Class Demand (Average Monthly)

1. The non-coincidental (system basis) class demand for the average month is assumed equal to the undiversified peak annual demand of 2,832 kW calculated above.

C. Assigned Coincidental Demand Responsibility -- Summer

kW = 0 [1]

D. Assigned Coincidental Demand Responsibility -- Winter

kW = 2,832 [1]

E. Assigned Coincidental Demand Responsibility -- Other

kW = 1,416 [1]

F. Assigned Class Coincidental Demand Responsibility (25% Summer, 25% Winter, 50% Other)

kW = 1,416 [1]

[1] See pages 39 and 40.

Dakota Electric

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

	Summer (kW)	Winter (kW)	Other (kW)
A. Non-Coincidental Class Demands			
Residential & Farm (31,32,53)	174,147	202,394	169,945
Residential & Farm Controlled A/C (8131)	70,316	0	11,719
Small General Service (41)	9,064	11,227	9,357
Small General Service Controlled A/C (8141)	1,255	0	209
Irrigation (36)	12,504	0	2,735
General Service (46)	117,323	92,283	96,931
General Service Peak Alert (70,71)	78,256	57,471	68,005
Street and Security Lighting	2,832	2,832	2,832
Total	465,697	366,207	361,734

	Summer (kW)	Winter (kW)	Other (kW)
B. Coincidence Factors (Summer)			
1. Other Classes			
Coincidence Factor			
Summer Coincidental Demand	326,853	229,990	219,605
Less:			
Residential & Farm Controlled A/C (8131)	35,158		5,860
Small General Service Controlled A/C (8141)	628		105
Irrigation (36)	396	0	87
General Service Peak Alert (70,71)	1,400	1,007	1,001
Street and Security Lighting	0	2,832	1,416
Total	289,271	226,152	211,137
Summer Non-Coincidental Demand	465,697		361,734
Less:			
Residential & Farm Controlled A/C (8131)	70,316	366,207	11,719
Small General Service Controlled A/C (8141)	1,255		209
Irrigation (36)	12,504	0	2,735
General Service Peak Alert (70,71)	78,256	57,471	68,005
Street and Security Lighting	2,832	2,832	2,832
Total	300,534	305,904	276,233
Coincidence Factor =	289,271	226,152	211,137
	300,534	305,904	276,233
=	96.25%	73.93%	76.43%

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

C. Assigned Coincidental Demand Responsibility (Summer Peak)

Rate Class	Summer Non-Coinc. Demand (kW)	Coinc. Factor	Summer Coinc. Demand (kW)
Residential & Farm (31,32,53)	174,147	0.9625	167,621
Plus: Controlled A/C	70,316	0.5000	35,158
Total Residential & Farm (31,32,53)	244,463	0.8295	202,779
Small General Service (41)	9,064	0.9625	8,724
Less Controlled A/C	1,255	0.5000	628
Total Small General Service (41)	10,319	0.9063	9,352
Irrigation (36)	12,504	0.0317	396 [1]
General Service (46)	117,323	0.9625	112,926
General Service Peak Alert (70,71)	78,256	0.0179	1,400
Street and Security Lighting	2,832	0.0000	0
Total	465,697		326,853

D. Assigned Coincidental Demand Responsibility (Winter Peak)

Rate Class	Winter Non-Coinc. Demand (kW)	Coinc. Factor	Winter Coinc. Demand (kW)
Residential & Farm (31,32,53)	202,394	0.7393	149,628
Small General Service (41)	11,227	0.7393	8,300
Irrigation (36)	0	0.0000	0
General Service (46)	92,283	0.7393	68,224
General Service Peak Alert (70,71)	57,471	0.0240	1,007
Street and Security Lighting	2,832	1.0000	2,832
Total	366,207		229,990

[1] Approximately 95.8% of the irrigation load is controlled so that it does not add to the GRE coincidental peak. Assume 75% coincident factor for the remaining customers.

Summer	0.042 x 12,504 kW x 0.75	396	kW (CD)	=	396
Other	0.042 x 2,735 kW x 0.75	87	kW (CD)	=	87

Estimate of Class Demands
(Continued)

VII. Estimate of Coincidental Demand

E. Assigned Coincidental Demand Responsibility (Other Peak)

Rate Class	Other Non-Coinc. Demand (kW)	Coinc. Factor	Other Coinc. Demand (kW)
Residential & Farm (31,32,53)	169,945	0.7643	129,896
Less Controlled A/C	11,719	0.5000	5,860
Net Residential & Farm (31,32,53)	181,664	0.7473	135,756
Small General Service (41)	9,357	0.7643	7,152
Less Controlled A/C	209	0.5000	105
Net Small General Service (41)	9,566	0.7586	7,257
Irrigation (36)	2,735	0.0317	87
General Service (46)	96,931	0.7643	74,089
General Service Peak Alert (70,71)	68,005	0.0320	1,001
Street and Security Lighting	2,832	0.5000	1,416
Total	361,734		219,605

F. Assigned Coincidental Demand Responsibility
(25% Summer, 25% Winter, 50% Other months)

	Ave. Coinc. Demand (kW)	Transm. & Anc. (kW)
Residential & Farm (31,32,53)	155,980	155,980
Small General Service (41)	8,041	8,041
Irrigation (36)	142	142
General Service (42)	82,332	82,332
General Service Peak Alert (70)	1,102	10,024
Street and Security Lighting	1,416	1,416
Total	249,013	257,935

General Service Peak Alert (70)		Class NCP	CF	Monthly Transm.	Annual Transm.
Summer	3 mos.	78,256	0.0179	1,400	4,200
Winter	3 mos.	57,471	0.2000	11,494	34,483
Other	6 mos.	68,005	0.2000	13,601	81,606
					120,289
					12
					10,024

<u>Development of Allocation Factors</u>

Line No.	Description	Units	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
1	**<u>Allocation Factor Input Data</u>**								
2	**Energy**								
3	Energy Sales -- All	MWh	1,769,404	838,684	42,538	7,964	463,060	406,800	10,359
4	Energy Sales -- Critical Peak	MWh							
5	Energy Sales -- On-Peak	MWh	591,321	281,636	14,284	2,674	155,499	136,606	622
6	Energy Sales -- Off-Peak	MWh	1,178,083	557,048	28,253	5,290	307,561	270,194	9,737
7	Dist. Losses	MWh	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%
8	Energy -- All @ Sub.	MWh	1,816,837	861,167	43,678	8,177	475,474	417,705	10,636
9	Energy -- Critical Peak @ Sub.	MWh							
10	Energy -- On-Peak @ Sub.	MWh	607,173	289,186	14,667	2,746	159,667	140,268	638
11	Energy -- Off-Peak @ Sub.	MWh	1,209,664	571,981	29,011	5,431	315,806	277,437	9,998
12	Trans. Losses	MWh							
13	Energy -- All @ Source	MWh	1,816,837	861,167	43,678	8,177	475,474	417,705	10,636
14	Energy -- Critical Peak @ Source	MWh							
15	Energy -- On-Peak @ Source	MWh	607,173	289,186	14,667	2,746	159,667	140,268	638
16	Energy -- Off-Peak @ Source	MWh	1,209,664	571,981	29,011	5,431	315,806	277,437	9,998
17	**Demand**								
18	Non-Coin. Demand @ Cons.	kW	1,122,260	772,748	35,427	21,856	183,608	105,789	2,832
19	Class Non-Coin. Demand @ Sub.	kW	387,771	201,097	9,755	4,702	101,451	67,934	2,832
20	Class Non-Coin. Demand Transm.	kW	387,771	201,097	9,755	4,702	101,451	67,934	2,832
21	Summer Coin. Demand	kW	326,853	202,779	9,352	396	112,926	1,400	
22	Winter Coin. Demand	kW	229,991	149,628	8,300		68,224	1,007	2,832
23	Other Coin. Demand	kW	219,605	135,756	7,257	87	74,089	1,001	1,416
24	Trans. Coin. Demand	kW	257,935	155,980	8,041	142	82,332	10,024	1,416
25									
26	**Average and Excess Demand**								
27	Average Demand	kW	207,402	98,307	4,986	933	54,278	47,683	1,214
28	Class Excess Demand	kW	180,369	102,790	4,769	3,769	47,173	20,251	1,618
29	Alloc. Excess Demand	kW	50,534	28,799	1,336	1,056	13,217	5,674	453
30	Avg. & Excess Demand	kW	257,935	127,105	6,322	1,989	67,494	53,357	1,667
31	**Revenue**								
32	Present Rate Revenue	$	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
33	Proposed Rate Revenue	$	197,242,256	112,877,123	5,701,055	912,232	50,388,052	25,295,556	2,068,238
34	**Consumer**								
35	No. Consumers		124,847	100,235	4,431	392	2,756	262	16,771
36	Pri. Line Weight. Factor			1.00	1.20	1.50	1.46	1.56	0.02
37	Weight. No. of Cons.		110,887.9	100,235.0	5,298.8	589.4	4,020.6	408.6	335.4
38	Transf. Weight. Factor			1.00	1.34	1.88	1.80	1.98	0.02
39	Weight. No. of Cons.		112,739.4	100,235.0	5,947.6	737.0	4,966.1	518.2	335.4
40	Service Weight. Factor			1.00	1.09	1.24	1.21	1.26	0.02
41	Weight. No. of Cons.		109,568.6	100,235.0	4,836.5	484.3	3,346.9	330.5	335.4
42	Meter Weight. Factor			1.00	1.37	2.88	3.17	14.74	0.02
43	Weight. No. of Cons.		120,374.1	100,235.0	6,071.0	1,130.3	8,740.5	3,861.9	335.4
44	Cons. Acct. Weight Factor			1.00	1.37	2.88	3.17	14.74	0.02
45	Weight. No. of Cons.		120,374.1	100,235.0	6,071.0	1,130.3	8,740.5	3,861.9	335.4

Development of Allocation Factors
(Continued)

Line No.	Description	Data Line No.	Name	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
46	**Allocation Factors**									
47	**Energy Related**									
48	Energy -- All @ Sub.	8	E1	1.000000	0.473992	0.024041	0.004501	0.261704	0.229908	0.005854
49	Energy -- Critical Peak @ Sub.	9	E2							
50	Energy -- On-Peak @ Sub.	10	E3	1.000000	0.476282	0.024157	0.004523	0.262968	0.231019	0.001051
51	Energy -- Off-Peak @ Sub.	11	E4	1.000000	0.472843	0.023982	0.004490	0.261069	0.229350	0.008265
52	Energy -- All @ Source	13	E5	1.000000	0.473992	0.024041	0.004501	0.261704	0.229908	0.005854
53	Energy -- Critical Peak @ Source	14	E6							
54	Energy -- On-Peak @ Source	15	E7	1.000000	0.476282	0.024157	0.004523	0.262968	0.231019	0.001051
55	Energy -- Off-Peak @ Source	16	E8	1.000000	0.472843	0.023982	0.004490	0.261069	0.229350	0.008265
56										
57	**Demand Related**									
58	Non-coin. Demand @ Cons.	18	D1	1.000000	0.688564	0.031567	0.019475	0.163606	0.094265	0.002523
59	Non-coin. Demand @ Class	19	D2	1.000000	0.518597	0.025156	0.012127	0.261627	0.175192	0.007303
60	Non-coin. Demand @ Transm	20	D3	1.000000	0.518597	0.025156	0.012127	0.261627	0.175192	0.007303
61	Summer Coin. Demand	21	D4	1.000000	0.620398	0.028611	0.001213	0.345495	0.004284	
62	Winter Coin. Demand	22	D5	1.000000	0.650583	0.036088		0.296638	0.004377	0.012314
63	Other Coin. Demand	23	D6	1.000000	0.618181	0.033044	0.000395	0.337374	0.004558	0.006448
64	Trans. Coin. Demand @ Sub.	24	D7	1.000000	0.604724	0.031175	0.000552	0.319196	0.038863	0.005490
65	Coin. Demand @ Source	25	D8							
66	Avg. & Excess	30	D9	1.000000	0.492779	0.024510	0.007713	0.261671	0.206862	0.006464
67										
68	**Revenue Related**									
69	Present Rate Revenue	32	R1	1.000000	0.572277	0.028904	0.004625	0.255463	0.128246	0.010486
70	Proposed Rate Revenue	33	R2	1.000000	0.572277	0.028904	0.004625	0.255463	0.128246	0.010486
71										
72	**Consumer Related**									
73	No. of Cons.	35	C1	1.000000	0.802863	0.035491	0.003140	0.022075	0.002099	0.134332
74	Pri. Line Weight. Cons.	37	C2	1.000000	0.903931	0.047786	0.005315	0.036259	0.003685	0.003025
75	Transf. Weight. Cons.	39	C3	1.000000	0.889086	0.052756	0.006537	0.044049	0.004597	0.002975
76	Services Weight. Cons.	41	C4	1.000000	0.914815	0.044141	0.004420	0.030546	0.003016	0.003061
77	Meter Weight. Cons.	43	C5	1.000000	0.832696	0.050434	0.009390	0.072611	0.032082	0.002786
78	Cons. Acct. Weight. Cons.	45	C6	1.000000	0.832696	0.050434	0.009390	0.072611	0.032082	0.002786

Docket No. E-111/GR-19-478

Exhibit__(DEA-2)
Determination of Revenue Requirements

Determination of Revenue Requirements - Summary

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Present Rates Pro Forma Test Year	(e) Proposed Rates Pro Forma Test Year
	Financial Results From Rates	($)	($)	($)
1	Total Revenue [1]	203,138,675	201,581,098	210,263,272
2	Operating Expense [1]	197,774,614	199,769,626	199,769,626
3	Net Operating Income (before interest expense) [2]	5,364,061	1,811,472	10,493,646
4	Capital Credits [3]	5,111,212	5,111,212	5,111,212
5	Other Non-Operating Income [3]	292,978	292,978	292,978
6	Total Margin (before interest expense) [4]	10,768,251	7,215,662	15,897,836
	Required Increase (Decrease) --ROR Objective			
7	Operating Expense (excluding interest) [1]	197,774,614	199,769,626	199,769,626
8	Margin Requirements			
9	Rate Base [5]	189,064,856	189,064,856	189,064,856
10	Rate of Return [6]	5.73%	5.73%	5.73%
11	Required Return [7]	10,831,846	10,831,846	10,831,846
12	Less: Non-Operating Income [3]	292,978	292,978	292,978
13	Net Operating Income Required [8]	10,538,868	10,538,868	10,538,868
14	Total Revenue Requirements [9]	208,313,482	210,308,494	210,308,494
15	Revenue Present Rates			
16	Tariff Revenue [1]	202,630,477	200,480,307	209,128,484
17	Other Operating Revenue [1]	508,198	1,100,791	1,134,788
18	Total Revenue [10]	203,138,675	201,581,098	210,263,272
19	Required Increase (Decrease) [11]	5,174,807	8,727,396	45,222
20	Percent Increase (Decrease) [12]	2.55	4.35	0.02

[1] See Exhibit__(DEA-1).
[2] Line 1 minus Line 2.
[3] See Workpaper 1.
[4] Line 3 plus Line 4 plus Line 5.
[5] See Exhibit__(DEA-2), page 2.
[6] See Exhibit__(DEA-2), page 8.
[7] Line 9 times Line 10.
[8] Line 11 minus Line 12.
[9] Line 7 plus Line 13.
[10] Line 16 plus Line 17.
[11] Line 14 minus Line 18.
[12] Line 19 divided by Line 16.

Rate Base

(a) **Line No.**	(b) **Description**	(c) **Proposed Pro Forma Test Year**
		($)
1	Utility Plant in Service [1]	300,342,133
2	Construction Work in Progress [1]	4,222,209
3	Less: Accumulated Provision for Deprec. [2]	126,526,023
4	Net Plant [1]	178,038,319
5	Materials & Supplies - Electric [3]	4,715,491
6	Working Capital [4]	6,816,147
7	Subtotal	11,531,638
8	Less: Consumer Deposits [1]	505,101
9	**Total Rate Base**	189,064,856

[1] December 31, 2018 Form 7 amount. See Workpaper 1.

[2] December 31, 2018 Form 7 amount adjusted to include Depreciation adjustment .
See Exhibit _ (DEA-1), page x.

[3] Thirteen - month average. See Exhibit__(DEA-2), page 3.

Rate Base Calculations
Materials & Supplies

(a) **Line No.**	(b) **Month**		(c) **Materials & Supplies Electric** [1] ($)
1	Dec	2017	4,472,686
2	Jan	2018	4,649,607
3	Feb	2018	4,676,986
4	Mar	2018	4,753,122
5	Apr	2018	4,953,466
6	May	2018	5,128,406
7	Jun	2018	4,907,896
8	Jul	2018	5,020,268
9	Aug	2018	4,854,970
10	Sep	2018	4,612,252
11	Oct	2018	4,752,223
12	Nov	2018	4,335,261
13	Dec	2018	4,184,242
14	**Total**		61,301,385
15	**13 - Month Average**		4,715,491

[1] Inventory accounts 13110 through 13320 from December 31, 2018 year end General Ledger.

Cost of Debt

(a) Line No.	(b) Description	(c) Interest Rate	(d) Estimated Balance	(e) Annualized Interest Expense [1]	(f) Target Debt	(g) Cost of Debt	(h) Weighted Cost of Debt
	Long Term Debt	(%)	($)	($)	(%)	(%)	(%)
1	CFC	3.400%	1,585,363	53,902			
2	CFC	4.500%	2,082,541	93,714			
3	CFC	4.050%	1,766,030	71,524			
4	CFC	4.250%	2,218,947	94,305			
5	CFC	3.500%	2,465,360	86,288			
6	CFC	3.800%	3,794,320	144,184			
7	CFC	3.550%	11,379,844	403,984			
8	CFC	3.550%	4,704,028	166,993			
9	CFC	3.750%	4,337,267	162,648			
10	CFC	3.300%	1,917,161	63,266			
11	CFC	2.500%	1,309,090	32,727			
12	CFC	3.600%	4,705,933	169,414			
13	CFC	3.750%	9,749,608	365,610			
14	CFC	4.250%	9,957,793	423,206			
15	CFC/Farmer Mac	4.250%	2,816,884	119,718			
16	CFC/Farmer Mac	3.830%	1,632,746	62,534			
17	CFC/Farmer Mac	3.970%	992,292	39,394			
18	CoBank	4.350%	1,059,986	46,109			
19	CoBank	2.590%	3,841,338	99,491			
20	CoBank	4.101%	4,904,209	201,122			
21	CoBank	3.500%	1,088,704	38,105			
22	CoBank	4.560%	4,332,287	197,552			
23	CoBank	3.950%	3,433,732	135,632			
24	CoBank	3.960%	3,738,278	148,036			
25	CoBank	1.910%	167,115	3,192			
26	CoBank	2.760%	1,546,883	42,694			
27	CoBank	3.960%	3,745,754	148,332			
28	CoBank	3.340%	4,574,903	152,802			
	Total Long Term Debt 12/31/2018 [2]		99,848,397	3,766,478	60%	3.77%	2.26%

[1] The Annualized Interest Expense is based on the Estimated Loan Balance multiplied by the loan interest rate.
[2] Equals Form 7, Part C, Line 38 (Long Term Debt) plus Line 45 (Current Portion) 93,460,696 + 6,387,701 = 99,848,397

Historic Total Capitalization

(a) Line No.	(b) Year	(c) Equity	(d) Debt	(e) Total Capitalization [1]
				($)
1	1998	47,724,259	89,235,673	136,959,932
2	1999	47,523,140	86,467,753	133,990,893
3	2000	48,277,127	86,508,221	134,785,348
4	2001	52,338,198	84,148,127	136,486,325
5	2002	56,192,068	91,885,042	148,077,110
6	2003	59,702,313	92,300,874	152,003,187
7	2004	60,411,502	104,332,408	164,743,910
8	2005	69,656,348	100,360,082	170,016,430
9	2006	81,417,061	101,287,278	182,704,339
10	2007	89,428,738	107,146,528	196,575,266
11	2008	94,900,838	107,846,291	202,747,129
12	2009	100,631,181	114,660,602	215,291,783
13	2010	109,245,168	115,021,054	224,266,222
14	2011	119,055,182	112,770,620	231,825,802
15	2012	127,764,369	98,368,388	226,132,757
16	2013	136,837,360	92,752,617	229,589,977
17	2014	147,409,115	96,605,051	244,014,166
18	2015	150,975,647	94,984,079	245,959,726
19	2016	161,294,191	93,878,841	255,173,032
20	2017	169,199,058	97,068,697	266,267,755
21	2018	173,151,167	99,848,397	272,999,564

The mean growth rate in Total Capitalization is estimated to be:

2013 - 2018 = 3.52%

Total Capitalization figures represent Margins & Equities plus Total Long-Term Debt for the years listed. See Workpaper 1 for years 2014 thru 2018.

Asset Growth Rate
Department of Commerce Methodology
(Natural Logarithm of a Number)

(a) *LN of* ***Assets***	(b) ***Year***	(c) ***Time***	(d) ***Assets*** [1]	(e) From LRF
19.6450	2018	1	340,193,777	340,193,777
19.6618	2019	2	345,961,418	345,961,418
19.6816	2020	3	352,873,712	352,873,712
19.6974	2021	4	358,477,813	358,477,813
19.7135	2022	5	364,321,717	364,321,717
19.7318	2023	6	371,018,880	371,018,880
19.7445	2024	7	375,785,642	375,785,642
19.7583	2025	8	380,994,230	380,994,230
19.7713	2026	9	385,996,186	385,996,186
19.7851	2027	10	391,362,529	391,362,529
19.8009	2028	11	397,573,959	397,573,959

0.0154 (10 yr. exponential GR)
0.0173 (5 yr. exponential GR)

1 Assets represent forecasted Assets for the years listed.
See Workpaper 5, Page 2.

Ratio Calculations
Department of Commerce Methodology

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Year	***Equity*** [1]	***Debt*** [2]	***Total Capital*** [3]	***Equity Ratio*** [4]	***Debt Ratio*** [5]	***Assets*** [6]	***Equity as % of Assets*** [7]
2019	175,914,526	105,640,524	281,555,050	0.6248	0.3752	345,961,418	50.85%
2020	177,214,989	111,540,354	288,755,343	0.6137	0.3863	352,873,712	50.22%
2021	178,231,219	116,416,226	294,647,445	0.6049	0.3951	358,477,813	49.72%
2022	179,402,896	121,376,453	300,779,349	0.5965	0.4035	364,321,717	49.24%
2023	180,280,744	127,483,768	307,764,512	0.5858	0.4142	371,018,880	48.59%
2024	179,749,233	133,070,041	312,819,274	0.5746	0.4254	375,785,642	47.83%
2025	179,718,738	138,597,124	318,315,862	0.5646	0.4354	380,994,230	47.17%
2026	178,123,694	145,364,127	323,487,821	0.5506	0.4494	385,996,186	46.15%
2027	176,747,430	152,394,734	329,142,164	0.5370	0.4630	391,362,529	45.16%
2028	176,124,124	159,517,470	335,641,594	0.5247	0.4753	397,573,959	44.30%
			5-yr average:	60.51%	39.49%		49.72%
			10-yr average:	57.77%	42.23%		47.92%

[1] See Workpaper 5
[2] See Workpaper 5
[3] Column b plus Column c
[4] Column b divided by Column d
[5] 1 minus Column e
[6] See Workpaper 5
[7] Column b divided by Column g

Overall Return on Rate Base
Department of Commerce Methodology

Assumptions:

1	Asset Growth Rate	1.73%
2	Equity Ratio	53.085%
3	Debt Ratio	46.915%
4	Test Year Total Capital	$ 272,999,564
5	Test Year Total Equity	$ 173,151,167
6	Test Year Total Debt	$ 99,848,397
7	Annual Capital Credits	$ 3,500,000
8	Rate Base	$ 189,064,856
9	Cost of Long-Term Debt	3.77%

Terms:

CC	Capital Credits
DR	Debt Ratio = (Debt/Total Capital)
ER	Equity Ratio = (Equity/Total Capital)
g	Growth in Equity
i	Cost of Long-Term Debt
K	Rate of Return on Equity
OCC	Overall Cost of Capital
RB	Rate Base
ROR	Return on Rate Base
TC	Total Capital
TIER	Times Interest Earned Ratio

DOC Method:

	g	ER	TC	CC
Return on Equity: K=g+(CC/(ER x TC))	0.0173	0.5309	272,999,564	$ 3,500,000

Return on Equity:	0.0414	K = g + (CC/(ER x TC))
Overall Cost of Capital (OCC):	0.0397	OCC = (ER x K) + ((1 - ER) x i)
Overall Return on Rate Base:	**0.0573**	ROR = OCC x (TC/RB)
Times Interest Earned Ratio:	2.24	TIER = ((K x ER) + (i x DR)) / (i x DR)

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1 5 Year Asset Growth Rate, See Exhibit__(DEA-2), Page 6
2 Average of 2022 and 2023 Equity Ratios, See Exhibit__(DEA-2), Page 7
3 1 - (Equity/Total Capital)
4 See DEA Exhibit_(DEA-2), Page 5
5 See DEA Exhibit_(DEA-2), Page 5
6 See DEA Exhibit_(DEA-2), Page 5
7 DEA Board Resolution 14-5-5 Long Range Financial Forecast
8
9 See DEA Exhibit_(DEA-2), Page 4

Docket No. E-111/GR-19-478

Exhibit __(DEA-1)
Statement of Operations -
Present Rates

Statement of Operations
Present Rates
Test Year - 2018 Historical Adjusted

(a) Line No.	(b) Description	(c) 2018 Actual	(d) Adjustments [1]	(e) Pro Forma Test Year	
1	**Operating Revenue**	($)	($)	($)	
2	Rate Schedules	202,630,477	(2,150,170)	200,480,307	[2]
3	Other	508,198	592,593	1,100,791	
4	**Total Operating Revenue**	203,138,675	(1,557,577)	201,581,098	
5	**Operating Expenses**				
6	Cost of Purchased Power	149,330,034	1,319,432	150,649,466	[3]
7	Transmission - O & M	-		-	
8	Distribution - Operation	7,277,184	(383,045)	6,894,139	
9	Distribution - Maintenance	6,151,338	242,574	6,393,912	
10	Consumer Accounts	5,312,955	380,854	5,693,809	
11	Consumer Service & Information	3,585,760	(180,461)	3,405,299	
12	Sales	-		-	
13	Administrative & General	11,907,838	71,783	11,979,621	
14	Depreciation & Amortization	10,281,975	404,073	10,686,048	
15	Taxes - Property	3,372,283	178,507	3,550,790	
16	Taxes - Other	-		-	
17	Other Interest Expense	549,008		549,008	
18	Other Deductions	6,239	(38,705)	(32,466)	
19	**Total Operating Expenses** (Before Long Term Interest)	197,774,614	1,995,012	199,769,626	
20	**Net Operating Income** (Before Long Term Interest)	5,364,061	(3,552,589)	1,811,472	

[1] The operating expense adjustments are summarized on pages 2 through 10.
[2] See pages 12 through 21 for Pro Forma Test Year Revenue.
[3] See page 22 for Pro Forma Test Year Purchased Power expense.

Summary of Test Year Adjustments to Operating Expenses

(a) Line No.	(b) Description		(c) 2018 Actual		(d) Adjustments		(e) Pro Forma Test Year	Change from 2018 Actual
	Operating Expenses							
1	Distribution - Operation (DO)	$	7,277,184	$	(383,045)	$	6,894,139	-5.3%
2	Distribution - Maintenance (DM)		6,151,338		242,574		6,393,912	3.9%
3	Consumer Accounts (CA)		5,312,955		380,854		5,693,809	7.2%
4	Consumer Service & Information (CS)		3,585,760		(180,461)		3,405,299	-5.0%
5	Sales				-		-	
6	Administrative & General (AG)		11,907,838		71,783		11,979,621	0.6%
7	Depreciation & Amortization		10,281,975		404,073		10,686,048	3.9%
8	Taxes - Property		3,372,283		178,507		3,550,790	5.3%
9	Taxes - Other		-		-		-	
10	Other Interest Expense		549,008		-		549,008	0.0%
11	Other Deductions		6,239		(38,705)		(32,466)	-620.4%
12	**Total Operating Expenses Excluding Purchased Power** (Before Long Term Interest)	$	48,444,580	$	675,580	$	49,120,160	1.4%
	Check Total							

Summary of Test Year Adjustments to Operating Expenses			Reference
Payroll			
General Payroll Increase	$	420,048	Page 3 of 22
Capital to Expense Changes		(65,168)	Page 4 of 22
Staffing Changes		260,379	Page 5 of 22
Total Payroll Adjustments		615,259	
Payroll Benefits			
Benefits on General Payroll Increase		197,171	Page 7 of 22
Benefits on Capital to Expense Changes		(30,590)	Page 7 of 22
Benefits on Staffing Changes		122,222	Page 7 of 22
Base Benefit Decrease		(393,317)	Page 6 of 22
Total Payroll Benefits		(104,514)	
Depreciation		404,073	Page 8 of 22
Other Adjustments		(118,505)	Page 10 of 22
Property Taxes		178,507	Page 8 of 22
Reduction in CIP Spending 2019 Budget to 2018 Actual		(200,296)	Page 9 of 22
Regulatory Filing Fees		18,800	Page 9 of 22
Rate Filing Fees recovery over 5 years		82,000	Page 10 of 22
Net Deduction for Disallowed Expenses		(199,744)	Page 10 of 22
Total Test Year Adjustments	$	675,580	

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL

GENERAL WAGE INCREASE

	Effective Date	Avg. % Increase	Wages Booked Prior To Increase	Wages Booked After Increase
			($)	($)
Union (Hourly Wages & OT)			Expensed	Expensed
Historical Test Year	1/1/18	2.50%	-	7,047,334
				Jan thru Dec
Future Test Year	1/1/19	2.50%	-	7,223,518
Non-Union (Salaries, PT, etc.)				
Historical Test Year	6/1/18	2.50%	3,745,930	5,462,416
			Jan thru Jun	Jul - Dec
Future Test Year	6/1/19	2.75%	3,839,578	5,612,632
Net Adjustment to Expensed Wages				**420,048**
Total Union & Non-Union			**Salaries & Wages Only**	**Total Comp inc OT, PT, etc.**
Historical			15,133,222	16,255,680
Future Test Year			15,524,462	16,675,728
Net Increase			2.6%	2.6%

Is the increase shown for the Future Test Year committed or still to be negotiated?

Union:	Committed
Non-Union:	Not Committed

CAPITAL TO EXPENSE CHANGE FOR NORMALIZED CONSTRUCTION YEAR

	% Expensed		Total Payroll		Expensed Payroll
Historical 2018 Test Year	86.0%	$	18,709,060	$	16,097,181
Average % Expensed 2015 thru 2018	85.7%				16,033,664
Additional Expensed for Normalized Year				$	(63,517)
Test Year Net Increase					2.6%
Net Additional Expensed for Normalized Year				$	(65,168)

Allocated to Operations & Maintenance Categories

Payroll Percentage Expensed History

		% Expensed	Total Payroll	Expensed Payroll
2	2015	86.1%	17,002,264	14,631,187
3	2016	85.9%	17,340,060	14,896,136
4	2017	84.8%	17,990,481	15,260,152
5	2018	86.0%	18,709,060	16,097,181
	Average over 4 years	85.7%		

Dakota Electric Association
TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL
STAFFING CHANGES

		Net Days Vacant	Incremental Wages Test Year	Wage Adjustment [1]
			($)	($)
Staffing Changes during Test Year	Category			
Member Service Representative - Bilingual (2 FTE's)	CA	125	18,628	9,314
Member Service Representative (2 FTE's)	CA	25	3,725	1,863
Energy Service Representative	CS	80	15,342	7,671
Lead Mechanic	AG	10	2,479	1,240
Mechanic (2 FTE's)	AG	129	30,456	15,228
Utility Services Secretary - PT	DM	50	7,157	3,579
Distribution System Operator Assistant	DO	64	10,179	5,090
Distribution System Operator	DO	56	12,305	6,153
Powerline Specialist Crew Chief	DM	41	11,785	5,893
Powerline Specialist Crew Chief	DM	19	5,461	2,731
Powerline Specialist Apprentice	DM	84	18,382	9,191
Powerline Specialist Apprentice	DM	274	59,959	29,980
Powerline Specialist Apprentice	DM	144	31,511	15,756
Powerline Specialist Apprentice	DM	34	7,440	3,720
Sr. Electrical Engineer	DO	87	26,934	13,467
Meter Technician	DO	127	31,468	15,734
System Design Manager	DO	29	10,964	5,482
Total		1,378	$ 304,175	$ 152,092
FTEs		4		50%
Distribution System Operator	DO	-252	(80,364)	(80,364)
Utility Services Superintendent	DM	-19	(8,900)	(8,900)
Vice President Engineering Services	AG	-28	(12,846)	(12,846)
Total Overlap				(102,110)
			Booked in Test Year	
Long Term Disability during Test Year				
Powerline Specialist Crew Chief	DM		10,049	94,866
New Positions Added during Test Year				
Director of Information Services Operations	AG		110,115	14,885
CIS/Billing Administrator	CA		3,635	60,665
Member Service Representative	CA		6,419	39,981
Total			130,218	210,397

Net Adjustment to Payroll for Staffing Changes	**$ 260,379**

[1] Additional wages which would have been booked had the individual been employed for the entire Historical Year assuming an average of 2 FTEs unfilled.

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS TO PAYROLL RELATED EXPENSE

	G/L Account Number	Rate: Historical Test Year	Rate: Future Test Year		Total Cost Historical Test Year
		(% of Payroll)	(% of Payroll)		($ Expensed)
Pension	81540-41	17.57%	16.71%	A	$ 2,680,484
Savings (401k)	81530-31	6.32%	6.77%	B	964,809
FICA Tax	81410	7.60%	7.60%		1,159,549
Life Insurance	81520	0.55%	0.60%		84,336
Workers' Compensation	82520	1.23%	1.32%		188,060
Medical Insurance	81510-15	12.55%	12.87%		1,915,268
State & Federal Unemployment	81420-30	0.16%	0.14%		23,855
Other-Retirement Health Benefits	81550	3.54%	0.93%	C	539,650
		49.5%	46.94%		$ 7,556,011
			Pro Forma Test Year Expensed Payroll Benefits		$ 7,162,694
			Adjustment		**$ (393,317)**
	Historical Test Year Expensed Salaries & Hourly Wages		15,259,255		

Notes:

A - Per NRECA, effective January 2019, the salaried and hourly rate is 28.93% and has increased 29pp from 2018. The decrease as a percent of total payroll is due to employee turnover as new hires are not eligible for the Retirement & Pension Plan.

B- Beginning March 1, 2006, new hires are not eligible for the Retirement & Pension Plan, but are enrolled in a new 401k plan where DEA will contribute 5% of base pay and will match up to an additional 5% of base pay. DEA contributes only 4% to employees that are in the pension plan. When employees with the pension retire at the lower rate and are replaced by new hires at the higher rate, the average rate increases.

C-The decrease in the Other-Retirement Health Benefits is due to a 2018 yearend accrual adjustment to the post-employment FAS 106 benefit related to the increase in medical insurance. This increase is not anticipated in 2019.

Dakota Electric Association

TEST YEAR ADJUSTMENTS SUMMARY
ADJUSTMENTS TO PAYROLL AND BENEFITS

SUMMARY OF COMPENSATION CHARGED TO EXPENSE ACCOUNTS

Category	Historical Test Year Expensed Compensation	General Payroll Increase	Capital to Expense Changes	Staffing Changes	Adjusted Test Year Expensed Compensation
	($)	($)	($)	($)	($)
I Operations	2,985,569	77,906	(33,389)	(34,438)	**2,995,648**
I Maintenance	2,841,645	74,151	(31,779)	156,816	**3,040,833**
(Consumer Accounting	2,113,151	55,142	-	111,823	**2,280,116**
(Consumer Services	1,001,465	26,133	-	7,671	**1,035,269**
/ Administration & General	7,116,699	185,707	-	18,507	**7,320,913**
Other (Diversified projects)	38,652	1,009	-	-	**39,661**
Construction	-	-	-	-	-
Total	16,097,181	420,048	(65,168)	260,379	**16,712,440**

SUMMARY OF PAYROLL BENEFITS CHARGED TO EXPENSE ACCOUNTS

Category	Historical Test Year Expensed Benefits	Benefits on General Payroll Increase	Benefits on Capital to Expense Changes	Benefits on Staffing Changes	Base Benefits Adjustment	Adjusted Test Year Expensed Benefits
		46.94%	46.94%	46.94%	-2.58%	
	($)	($)	($)	($)	($)	($)
Operations	1,401,425	36,569	(15,673)	(16,165)	(72,949)	**1,333,207**
Maintenance	1,333,867	34,806	(14,917)	73,609	(69,432)	**1,357,933**
Consumer Accounting	991,912	25,884	-	52,490	(51,633)	**1,018,653**
Consumer Services	470,087	12,267	-	3,601	(24,470)	**461,485**
Administration & General	3,340,577	87,171	-	8,687	(173,889)	**3,262,546**
Other (Diversified projects)	18,143	474	-	-	(944)	**17,673**
Construction	-	-	-	-	-	-
Total	7,556,011	197,171	(30,590)	122,222	(393,317)	**7,451,497**

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER

<u>Adjustment to Depreciation</u>	
Depreciation on Existing Plant	
1. Depreciation expense for the month of December 2018:	$ 890,504
2. Multiply by 12 months.	12
3. Normalized Depreciation Expense on Existing Plant	$ 10,686,048
Depreciation for the Pro Forma Test Year	$ 10,686,048
Less Historical 2018 Depreciation	(10,281,975)
Adjustment for Test Year	$ 404,073
<u>Adjustment to Property Tax Expense</u>	
1. Property Tax booked in the Historical Test Year:	$ 3,371,493
2. Property Tax to be booked in the next 12 months:	3,550,000
Property Tax Adjustment	$ 178,507

Note:

Current annual depreciation rates are outlined in the 5-year depreciation study in Docket No. E111/D-17-505.

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER
(continued)

Projected Reduction in Total CIP Spending 2018 Actual to 2019 Budget

2019 Budget CIP Spending		$ 2,206,786
2018 Actual Spending		2,407,082
Adjustment for CIP Spending	908	$ (200,296)

Adjustment to Regulatory Filing Fees

1.	Indirect Assessments for 2019 Budget	$ 344,000
2	Direct Assessments for 2019 Budget	85,000
	Total Assessments	$ 429,000
Assessments for the Pro Forma Test Year		$ 429,000
Less Historical 2018 Filing Fees		$ (410,200)
Adjustment for Test Year		$ 18,800

Dakota Electric Association

TEST YEAR ADJUSTMENTS
ADJUSTMENTS - OTHER
(continued)

	FERC Acct		Project Code		
Adjustment for Rate Filing Expense					
Estimated Rate Filing Expense (excluding internal labor)			RATECASE19	$	410,000
Amortize over 5 years					5
Adjustment (to A&G Expense)	928			$	82,000
Adjustment for nonrecurring reimbursements					
Adjustment for nonrecurring reimbursements				$	-
Other Adjustments					
Normalize Contracted Services for Kubra Data Transfer Services				$	36,758
Normalize Contracted Services for Itineris					109,080
Normalize Collection Recovery Costs					27,358
Normalize Contracted Services for meter reading					13,952
Normalize for Circuits Redesign and advertising removal					2,300
Distributed Generation contracts terminated					19,320
Subsidiaries contracts terminated					6,129
Dispatching contracts terminated					24,308
Internet project completed (only depreciation remaining)					(8,496)
Removal of AGi project					(382,291)
New broadband lease agreement (shared expense with GRE)					33,077
Other Adjustments				$	(118,505)
Adjustment for Disallowed Expenses			Project		
Exclude Touchstone Energy Branding Project	920		BRANDING		(115,225)
Exclude Image bill insert	909		Portion of MKT		(7,667)
Customer Relations Disallowed Expenses:					
Exclude Customer Zoo Event	930		CUSEVENT		(37,608)
Subtract 50% of Donation Project $ Disallowed:					
Community Donations	426.1	50%	DONCOMM		(8,663)
Human Services Donations	426.1	50%	DONHUMSV		(6,873)
Special Donations	426.1	50%	DONSPEC		(9,500)
Youth Donations	426.1	50%	DONYOUTH		(13,958)
Other Donations	426.1	50%	Various		(250)
				$	(199,744)

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

I. Consumer and Sales Data for 2018 (As Recorded)

(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**Avg. No. Cons.**	**Energy Sales [1]**	**Billing Demand [1]**	**Revenue [1]**
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	99,322	867,819,897	N.A.	116,867,077
2	Residential & Farm Demand Control (32)	15	407,603	989	45,353
3	Electric Vehicle (33)	0	332,257	N.A.	25,854
4	Irrigation Service (36) Firm	9	301,498	3,464	90,636
5	Irrigation Service (36) Interruptible	382	8,585,963	81,869	961,923
6	Small General Service (41)	4,426	42,642,557	N.A.	5,744,594
7	Security Lighting Service (44) - Closed to New	831	446,106	N.A.	102,393
8	Street Lighting Service (44-2)	2,284	2,487,972	N.A.	463,839
9	Street Lighting System (44-1)	487	523,536	N.A.	70,135
10	Custom Residential Street Lighting (44-3)	12,233	7,432,586	N.A.	1,331,468
11	LED Security Lighting Service (44 -4)	338	63,709	N.A.	30,558
12	LED Street Lighting Member Owned(44-5)	11	8,056	N.A.	1,196
13	LED Street Lighting (44-6)	465	171,871	N.A.	51,719
14	Low Wattage Unmetered Service (45)	66	-	N.A.	7,888
15	General Service (46)	2,696	449,957,114	1,404,899	48,236,894
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	3	203,303	N.A.	19,781
18	Controlled Energy Storage (51)	1,280	10,853,238	N.A.	501,196
19	Controlled Interruptible Service (52)	6,403	49,078,197	N.A.	2,949,495
20	Residential & Farm Time of Day (53)	18	217,249	N.A.	27,157
21	General Service Time of Day (54)	6	1,143,456	7,338	134,668
22	Standby Service (60)	1	-	-	65,387
23	Full Interruptible Service (70)	233	384,258,036	870,612	24,613,715
24	Partial Interruptible Service (71)	27	25,529,544	102,790	2,062,689
25	Cycled Air Conditioning Service (80)	41,630	4,754,757	N.A.	(1,786,057)
26	Wellspring				6,959
27	**Total [2]**	107,135	1,852,463,748	2,471,961	202,630,477

[1] See Workpaper 12.

[2] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) 2019 Budget Avg No. Cons. [1]	(d) Energy Sales [2]	(e) Billing Demand [2]	(f) Revenue [3]
			(kWh)	(kW)	($)
1	Residential & Farm Service (31)	100,202	838,089,528	N.A.	114,332,035
2	Residential & Farm Demand Control (32)	15	378,000	917.2	42,670
3	Electric Vehicle (33)	88	300,960	N.A.	24,636
4	Irrigation Service (36) Firm	8	162,528	1,867.3	50,143
5	Irrigation Service (36) Interruptible	384	7,801,344	74,387.5	862,089
6	Small General Service (41)	4,431	42,537,600	N.A.	5,799,609
7	Security Lighting Service (44) - Closed to New	878	405,600	N.A.	102,369
8	Street Lighting Service (44-2)	2,269	2,405,280	N.A.	466,293
9	Street Lighting System (44-1)	470	521,040	N.A.	72,603
10	Custom Residential Street Lighting (44-3)	12,190	6,750,960	N.A.	1,334,683
11	LED Security Lighting Service (44 -4)	356	64,896	N.A.	31,109
12	LED Street Lighting Member Owned(44-5)	11	8,712	N.A.	1,297
13	LED Street Lighting (44-6)	597	202,152	N.A.	59,884
14	Low Wattage Unmetered Service (45)	71	-	N.A.	8,520
15	General Service (46)	2,750	462,000,000	1,442,500.4	50,261,766
16	Municipal Civil Defense Sirens (47)	66	-	N.A.	3,960
17	Geothermal Heat Pump (49) Closed to New	*3*	172,800	N.A.	16,571
18	Controlled Energy Storage (51)	1,718	10,308,000	N.A.	459,736
19	Controlled Interruptible Service (52)	6,686	44,127,600	N.A.	2,634,418
20	Residential & Farm Time of Day (53)	18	216,216	N.A.	29,057
21	General Service Time of Day (54)	6	1,059,984	6,802.3	126,286
22	Standby Service (60)	1	-		66,840
23	Full Interruptible Service (70)	234	379,080,000	858,880.1	23,144,467
24	Partial Interruptible Service (71)	28	27,720,000	111,609.5	2,151,089
25	Cycled Air Conditioning Service (80)	41,880	5,075,000	N.A.	(1,625,193)
26	Wellspring				23,370
27	**Total** [4]	108,165	1,824,313,200	2,496,964.3	200,480,307
28	Actual Revenue Recorded 2018				202,630,477
29	Adjustment				(2,150,170)

[1] Pro Forma Test Year consumers are based on DEA's average number of 2019 budgeted consumers.

[2] Energy Sales are based on average monthly sales using the higher of 7-10 year trend or budget multiplied by average budgeted 2019 number of customers. See Workpaper 13.

[3] See page 13 through 21.

[4] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service , Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Residential & Farm Service (31)				($)
Fixed Charge	100,202	cons.	$9.00	10,821,816
Energy Charge	838,089,528	kWh		
Summer	257,025,312	kWh	$0.13080	33,618,911
Other	581,064,216	kWh	$0.11680	67,868,300
			Subtotal	112,309,027
RTA Charge [1]	838,089,528	kWh	$0.00250	2,095,224
Controlled Water Heater Credit	1,003	units	($6.00)	(72,216)
			Total	114,332,035
Residential & Farm Demand Control (32)				
Fixed Charge	15	cons.	$12.00	2,160
Demand Charge	917.2	kW		
Summer	182.2	kW	$14.70	2,678
Other	735.0	kW	$11.10	8,159
Energy Charge	378,000	kWh	$0.07600	28,728
			Subtotal	41,725
RTA Charge [1]	378,000	kWh	$0.00250	945
			Total	42,670
Electric Vehicle (33)				
Energy Charge				
Off Peak	280,402	kWh	$0.06740	18,899
On Peak	8,554	kWh	$0.41440	3,545
Other				
Summer	2,693	kWh	$0.13080	352
Other	9,311	kWh	$0.11680	1,088
			Subtotal	23,884
RTA Charge [1]	300,960	kWh	$0.00250	752
				24,636

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Irrigation Service (36)				
Firm Service				
Fixed Charge	8	cons.	$30.00	2,880
Demand Charge	1,867.3	kW		
Summer	902.3	kW	$26.35	23,776
Winter	2.5	kW	$20.95	52
Other	962.5	kW	$15.50	14,919
Energy Charge	162,528	kWh	$0.04990	8,110
			Subtotal	49,737
RTA Charge [1]	162,528	kWh	$0.00250	406
			Total	50,143
Interruptible Service				
Fixed Charge	384	cons.	$30.00	138,240
Demand Charge	74,388	kW	$4.55	338,463
Energy Charge	7,801,344	kWh	$0.04990	389,287
			Subtotal	865,990
RTA Charge [1]	7,801,344	kWh	($0.00050)	(3,901)
			Total	862,089
Small General Service (41)				
Fixed Charge	4,431	cons.	$14.00	744,408
Energy Charge	42,537,600	kWh		
Summer	10,541,910	kWh	$0.12690	1,337,768
Other	31,995,690	kWh	$0.11290	3,612,313
			Subtotal	5,694,489
RTA Charge [1]	42,537,600	kWh	$0.00250	106,344
Controlled Water Heater Credit	17	units	($6.00)	(1,224)
			Total	5,799,609

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
Security Lighting Service (44)				
175 W MV	0	lights	N/A	0
100 W HPS	819	lights	$10.10	99,263
150 W HPS	4	lights	$11.99	576
250 W HPS	8	lights	$15.79	1,516
	831	lights	Subtotal	101,355
RTA Charge [1]	405,600	kWh	$0.00250	1,014
			Total	102,369
Street Lighting Service (44-2)				
175 W MV	-	lights	$15.23	0
250 W MV	3	lights	$18.16	654
400 W MV	-	lights	$23.25	0
100 W HPS	38	lights	$12.27	5,595
150 W HPS	646	lights	$14.16	109,768
250 W HPS	1,597	lights	$17.95	343,994
400 W HPS	1	lights	$22.38	269
	2,285	lights	Subtotal	460,280
RTA Charge [1]	2,405,280	kWh	$0.00250	6,013
			Total	466,293
Street Lighting System (44-1)				
175 W MV	-	lights	$10.52	0
250 W MV	-	lights	$13.46	0
400 W MV	-	lights	$18.54	0
100 W HPS	-	lights	$7.56	0
150 W HPS	101	lights	$9.46	11,466
200 W HPS	101	lights	$11.41	13,829
250 W HPS	272	lights	$13.25	43,248
400 W HPS	13	lights	$17.67	2,757
	487	lights	Subtotal	71,300
RTA Charge [1]	521,040	kWh	$0.00250	1,303
			Total	72,603

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Custom Residential Street Lighting (44-3)				
175 W MV	-	lights	$11.37	0
50 W HPS	81	lights	$6.70	6,512
100 W HPS	8,416	lights	$8.41	849,343
150 W HPS	3,732	lights	$10.30	461,275
250 W HPS	4	lights	$14.09	676
	12,233	lights	Subtotal	1,317,806
RTA Charge [1]	6,750,960	kWh	$0.00250	16,877
			Total	1,334,683
LED Security Lighting (44-4)				
LED, >4,500 Lumens	338	lights	$7.63	30,947
RTA Charge [1]	64,896	kWh	$0.00250	162
				31,109
LED Street Lighting Member Owned(44-5)				
A (40-80 watts)	-	lights	$ 4.81	-
B (81-150 watts)	-	lights	$ 6.71	-
C (151-250 watts)	11	lights	$ 9.66	1,275
D (251-350 watts)	-	lights	$ 13.05	-
E (351-450 watts)	-	lights	$ 16.52	-
	11		Subtotal	1,275
RTA Charge [1]	8,712	kWh	$0.00250	22
				1,297

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue ($)
LED Street Lighting (44-6)				
Standard				
>5,200 L, Coach (Post)	121	lights	$10.60	15,391
>5,200 L, Acorn (Post)	48	lights	$11.24	6,474
>7,000 L, Cobra (Mast)	91	lights	$8.31	9,075
>11,500 L, Shoebox	151	lights	$10.71	19,407
Basic				
>5,200 L, Coach (Post)	41	lights	$6.83	3,360
>5,200 L, Acorn (Post)	0	lights	$6.30	-
>7,000 L, Cobra (Mast)	53	lights	$6.51	4,140
>11,500 L, Shoebox	16	lights	$7.98	1,532
	521			59,379
RTA Charge [1]	202,152	kWh	$0.00250	505
				59,884
Low Wattage Unmetered Service (45)				
Fixed Charge	71	cons.	$10.00	8,520
General Service (46)				
Fixed Charge	2,750	cons.	$34.00	1,122,000
Demand Charge	1,442,500.4	kW		
Summer	413,627.7	kW	$12.26	5,071,076
Other	1,028,872.7	kW	$9.16	9,424,474
Energy Charge				
First 200 kWh/kW	264,418,387	kWh	$0.07760	20,518,867
Next 200 kWh/kW	158,964,776	kWh	$0.06760	10,746,019
Over 400 kWh/kW	38,616,837	kWh	$0.05760	2,224,330
			Subtotal	49,106,766
Discounts				
Primary Voltage			($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	462,000,000		$0.00250	1,155,000
			Total	50,261,766

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Municipal Civil Defense Sirens (47)				
Fixed Charge	66	cons.	$5.00	3,960
Geothermal Heat Pump (49)				
Energy Charge	172,800	kWh	$0.09400	16,243
			Subtotal	16,243
RTA Charge [1]	172,800	kWh	$0.00190	328
			Total	16,571
Controlled Off-Peak Space & Energy Storage (51)				
Energy Net Charge - Rate 31	*10,210,445*	kWh		
Summer	2,701,434	kWh	$0.04400	118,863
Other	7,509,011	kWh	$0.04400	330,396
Energy Charge - Rate 41	*46,106*	kWh		
Summer	6,874	kWh	$0.04400	302
Other	39,232	kWh	$0.04400	1,726
Energy Charge - Rate 46	*51,449*	kWh	$0.04400	2,264
			Subtotal	453,551
RTA Charge [1]	10,308,000	kWh	$0.00060	6,185
			Total	459,736
Interruptible Heating Service (52)				
Energy Net Charge - Rate 31	*43,026,625*			
Summer	10,488,495	kWh	$ 0.05500	576,867
Other	32,538,130	kWh	$0.05500	1,789,597
Energy Charge - Rate 41	*450,886*			
Summer	64,095	kWh	$0.05500	3,525
Other	386,791	kWh	$0.05500	21,274
Energy Charge - Rate 46	650,089	kWh	$0.05500	35,755
			Subtotal	2,427,018
RTA Charge [1]	44,127,600	kWh	$0.00470	207,400
			Total	2,634,418

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Residential & Farm Time of Day (53)				
Fixed Charge	18	cons.	$12.00	2,592
Energy Charge				
Peak Period				
Summer	49,267	kWh	$0.18800	9,262
Other	12,117	kWh	$0.17400	2,108
Off-Peak Period	154,832	kWh	$0.09400	14,554
		kWh	Subtotal	28,516
RTA Charge [1]	216,216	kWh	$0.00250	541
			Total	29,057
General Service Time of Day (54)				
Fixed Charge	6	cons.	$36.00	2,592
Demand Charge	6,802.3			
Peak Period				
Summer	960.1	kW	$24.85	23,858
Winter	436.9	kW	$18.95	8,279
Other	1,253.2	kW	$13.00	16,292
Maximum	4,152.1	kW	$4.75	19,722
Energy Charge	1,059,984	kWh	$0.04990	52,893
			Subtotal	123,636
Discounts				
Primary Voltage		kW	($0.15)	
Primary Metering			(2.00%)	
RTA Charge [1]	1,059,984	kWh	$0.00250	2,650
			Total	126,286
Standby Service Large Power General (60)				
Generation Reservation Fee				
Summer	1,000	kW	$3.21	9,630
Winter	1,000	kW	$2.47	7,410
Other	1,000	kW	$1.74	10,440
Distribution Reservation Fee				
Primary	1,000	kW	$3.2800	39,360
Secondary		kW	$3.5100	0
			Total	66,840

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Full Interruptible Service (70)				
Fixed Charge	234	cons.	$110.00	308,880
Communication Fee	51		$8.70	5,324
Coinc. Demand Charge				
Summer	1,042.8	kW	$24.85	25,914
Winter	0.0	kW	$18.95	0
Other	0.0	kW	$13.00	0
Total Coinc Demand	1,042.8	kW		
Non-Coinc. Demand	858,880.1	kW	$4.75	4,079,680
Failure to Control	1,042.8		$5.00	5,214
Energy Charge	379,080,000	kWh	$0.04990	18,916,092
Discounts			Subtotal	23,341,104
Primary Voltage	47,311.12	kW	($0.15)	($7,097)
Primary Metering	-		(2.0%)	$0
RTA Charge [1]	379,080,000	kWh	($0.00050)	(189,540)
			Total	23,144,467
Partial Interruptible Service (71)				
Fixed Charge	28	cons.	$110.00	36,960
Communication Fee	17		$8.70	1,775
Coinc. Demand Charge				
Summer	3,212.2	kW	$24.85	79,823
Winter	2,980.2	kW	$18.95	56,475
Other	5,964.3	kW	$13.00	77,536
Total Coinc Demand	12,156.7	kW		
Non-Coinc. Demand	111,610	kW	$4.75	530,145
Excess Demand		kW	$5.00	0
Energy Charge	27,720,000	kWh	$0.04990	1,383,228
Discounts			Subtotal	2,165,942
Primary Voltage	6,622.67	kW	$0.15	(993)
Primary Metering	0		2.00%	-
RTA Charge [1]	27,720,000	kWh	($0.00050)	(13,860)
			Total	2,151,089

[1] 2019 applied RTA.

Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

III. Estimate of Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
				($)
Controlled Air Conditioning Service (80)				
Option 1		kWh	$0.00	0
Option 2				
Residential Rate 81/31	4,858,654	kWh	($0.03200)	(155,477)
Rate 81/41	216,346	kWh	($0.03200)	(6,923)
Rate 81/46	0	kWh	($0.03200)	0
	5,075,000	kWh		(162,400)
Option 3				
Residential Rate 82/31	35,158	cons.	($13.00)	(1,371,162)
Commercial	0	cons.	($13.00)	0
	35,158			(1,371,162)
Option 4				
Rate 84/41	4,699	tons	($6.50)	(91,631)
Rate 84/46	0	tons	($6.50)	0
	4,699			(91,631)
			Total	(1,625,193)
Wellspring				23,370
Grand Total	1,824,313,200	kWh		$ 200,480,307

Estimate of Pro Forma
Test Year Purchased Power Expense

(a) Line No.	(b) Description		(c) Units			(d) Rate		(e) Cost
	Based on GRE Year 2019 Rates [1]							($)
1	**GRE General Purchases**							
2	Capacity Charge [2]							
3	Summer - Gross		1,169,412.0	kW				
4	Less Demand Credits		(188,852.0)	kW				
5	Summer - Net		980,560.0	kW	$	18.24	/kW	17,885,414
6								
7	Winter		841,113.0	kW				
8	Less Demand Credits		(151,142.0)	kW				
9	Winter - Net		689,971.0	kW	$	12.16	/kW	8,390,047
10								
11	Other		1,635,745.0	kW				
12	Less Demand Credits		(318,115.0)	kW				
13	Other - Net		1,317,630.0	kW	$	6.08	/kW	8,011,190
14	Total Demand - Net		2,988,161.0	kW				34,286,651
15								
16	Energy Charge							
17	Wholesale Solar		4,500,000	kWh	$	0.060494	/kWh	272,224
18	On Peak		620,577,032	kWh	$	0.059390	/kWh	36,856,070
19	Off Peak		1,248,141,635	kWh	$	0.046460	/kWh	57,988,660
20	Ancillary Charge		1,873,218,667	kWh	$	0.000090	/kWh	168,590
21								
22	Transmission Charge		3,119,782.8	kW	$	6.57	/kW	20,496,973
23	Ancillary Charge		3,119,782.8	kW	$	0.69	/kW	2,152,650
24								
25	ETS-Space Heating Off Peak		1,323,100	kWh	$	(0.023960)	/kWh	(31,701)
26	ETS-Interruptible Water Heating Off Peak		6,187,000	kWh	$	(0.026460)	/kWh	(163,708)
27	ETS-Electric Vehicle Off Peak		264,300	kWh	$	(0.026460)	/kWh	(6,993)
28	Peak Shave Water Heating (8 hr) Off Peak		14,844,800	kWh	$	(0.012460)	/kWh	(184,966)
29	Peak Shave Water Heating (8 hr) On Peak		6,362,100	kWh	$	(0.025390)	/kWh	(161,534)
30	Dual Fuel Off Peak		12,961,800	kWh	$	(0.009960)	/kWh	(129,100)
31	Dual Fuel On Peak		5,555,100	kWh	$	(0.022890)	/kWh	(127,156)
32	Air Conditioner Credit	(3 Mo.)				$5.00	/unit/mo.	(772,584)
33								
34	Standby Reservation Fee		1	cons.		$27,060.00	/year	27,060
35	Wellspring							23,370
36	MSR Credit							(45,040)
37	**Total Test Year Purchased Power Cost**							150,649,466
38	Actual Purchased Power Recorded 2018							149,330,034
39	Adjustment							1,319,432

[1] Test Year Rates are GRE's Year 2019 updated rates. Includes a direct pass through of Wellspring costs.
[2] The Test Year capacity is based on 2019 budget
[3] Wholesale Solar purchases are 2019 budget.

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates for
Electric Service in Minnesota

Docket No. E-111/GR-19-478

PREFILED DIRECT TESTIMONY OF
DOUGLAS R. LARSON
VICE PRESIDENT OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION,
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PREFILED DIRECT TESTIMONY OF
DOUGLAS R. LARSON
VICE PRESIDENT OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

I. QUALIFICATIONS

Q. Please state your name.

A. My name is Douglas R. Larson.

Q. Where are you employed?

A. I am employed by Dakota Electric Association (DEA, Dakota Electric, or Cooperative). Dakota Electric's headquarters are located at 4300 220th Street West, Farmington, Minnesota 55024.

Q. Please describe the business activities of Dakota Electric.

A. Dakota Electric Association was founded in 1937 as a non-profit, member-owned distribution electric utility. It serves about 108,000 members in an area covering much of Dakota County, just south of Minneapolis and St. Paul. Dakota Electric also provides electric service in portions of Scott, Rice and Goodhue counties.

Dakota Electric purchases wholesale electricity from Great River Energy (GRE), located in Maple Grove, Minnesota.

A twelve-person elected board of directors made up of members governs the Cooperative. Dakota Electric is also regulated by the Minnesota Public Utilities Commission and is the only rate-regulated electric cooperative in Minnesota.

Q. Please state your title and describe your responsibilities with Dakota Electric Association.

A. I am Vice President of Regulatory Services. In this position, I am responsible for 1) developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; 2) evaluating power supply issues through participation in meetings at Great River Energy; and 3) monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Q. What is your educational and professional background?

A. My educational and professional background is summarized in Schedule 1 attached to this direct testimony.

Q. Have you previously presented testimony before the MPUC?

A. Yes. Schedule 2 attached to this direct testimony identifies the electric and natural gas utility general rate case proceedings, electric service territory compensation hearings, the contested rulemaking and the certificate of need proceeding in which I have presented testimony before the MPUC.

Q. Have you submitted testimony to other state regulatory commissions?

A. Yes. Schedule 2 attached to this direct testimony also identifies the electric utility general rate case proceedings in which I have presented testimony before other state regulatory commissions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the analysis of Dakota Electric's revenue requirements, class cost of service study and proposed rates within the context of the 2018 Historical Test Year, adjusted for known and measurable changes.

Q. Please describe the organization of your direct testimony.

A. My direct testimony is organized around the following sections with topics covered as follows:

Section I — Qualifications
- Identification
- Educational and professional background
- Previous testimony

Section II — Purpose of Testimony
- Organization of testimony
- Identification of exhibits
- Identification of workpapers

Section III — Summary of Filing

Section IV — Revenue Requirements
- Statement of Operations
- Rate of Return

Section V — Cost of Service Study
- COS overview
- Identify COS content
- General procedure for conducting COS
- Identify and summarize COS results

Section VI — Other Cost Analyses
- Load Management Cost Analysis

- Monthly Fixed Charge Cost Analysis
- Coincidental Demand Charges
- Special Fees and Charges
- Line Extension Analysis
- Base Calculations for Resource and Tax Adjustment
- Air Conditioning Analysis
- Standby Rate Analysis
- Electric Vehicle Rate Analysis
- Residential TOU Analysis

Section VII Rate Design

- Approach to rate design
- Proposed rates

Section VIII Summary and Conclusion

Q. Please identify the exhibits included with your testimony.

A. The following exhibits are included as part of my testimony:

Exhibit__(DEA-1)	Statement of Operations - Present Rates
Exhibit__(DEA-2)	Determination of Revenue Requirements
Exhibit__(DEA-3)	Cost of Service Analysis
Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-5)	Statement of Operations - Proposed Rates
Exhibit__(DEA-6)	Comparison of Present and Proposed Rates
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-9)	Summary of Lead-Lag Study
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU Rate Analysis
Exhibit__(DEA-17)	Present Rate Schedules
Exhibit__(DEA-18)	Blackline Mark-up of Present Rate Schedules
Exhibit__(DEA-19)	Proposed Rate Schedules

Q. Please identify the documents included in the workpapers you have submitted:

A. The workpapers include the following documents:

1) Form 7s 2014-2018
2) Audited 2018 Financials and 2018 Annual Report
3) Accounting System Description and Cross-Reference Projects to Form 7
4) 2019 Budget (2017 & 2018 Actual)
5) Long Range Forecast
6) Lead-Lag Study Detail
7) Cost Allocation Policy
8) Depreciation Summary
9) Conservation Improvement Program
10) Estimate of System Losses and System Own Use
11) Individual Customer Actual 2018 Usage and Demand by Rate Class
12) Monthly Billed Sales 2013-2018
13) Sales History and Forecasted Test Year Normalization
14) Property Tax Detail
15) Travel, Entertainment and Related Employee Expenses
16) Test Year Adjustments Bridge Schedule
17) Long Term Interest Expense / Prudently Incurred
18) Advertising
19) Donations / Charitable Contributions
20) Organizational Dues
21) Minimum Size Method w/ Demand Adjustment
22) Guide to the Cost of Service Study
23) Street Lighting Analysis
24) Reconciliation
25) Smart Metering Statement

Q. Has the material included in your exhibits and workpapers been prepared by you or by others under your direction?

A. The exhibits and workpapers I am sponsoring have been prepared by myself and others at Dakota Electric. In addition, the cost of service study model was completed by Richard J. Macke at Power System Engineering, Inc.

III. SUMMARY OF FILING

Q. What are Dakota Electric's objectives in filing this general rate case?

A. Dakota Electric has two objectives in filing this general rate case. The first objective is financial. Dakota Electric's 2019 budget has negative operating margins of about ($2,250,000), making an increase in rates necessary. This general rate filing will allow the Cooperative to increase distribution operating revenues and achieve acceptable financial operating results. The second objective of this general rate filing is to make continuing adjustments to align class rates and revenue with the cost of providing service.

Q. Would you please summarize the revenue requirement, COS study results and proposed rate design results contained in your testimony?

A. Revenue Requirements -- Summary

The revenue requirements of the Cooperative simply refer to the total cost of doing business and are comprised of operating expenses plus margin requirements. By comparing the revenue requirements against present revenue, the adequacy of the present rates can be assessed; and a general change in rates can be discussed.

Operating expenses for the Cooperative (excluding interest) total $199,769,626. We have calculated a proposed Rate of Return (ROR) on rate base of 5.73 percent, resulting in a required revenue increase of $8,727,396 or 4.35 percent. The following table presents a summary of the revenue requirements analysis for the 2018 Test Year:

Table 1
Revenue Requirements Summary

		($)
1.	Operating Expenses (Excluding Interest)	199,769,626
2.	Margin Requirements	
	a. Rate Base	189,064,856
	b. Rate of Return	5.73%
	c. Return Required	10,831,846
	d. Less: Non-Operating Income	292,978
	e. Net Operating Income Required	10,538,868
3.	Total Revenue Requirements	210,308,494
4.	Revenue from Present Rates	
	a. Tariff Revenue (net of RTA)	200,480,307
	b. Other Operating Revenue	1,100,791
	c. Total Revenue	201,581,098
5.	Potential Increase (Decrease)	8,727,396
	or	4.35%

Class Cost of Service -- Summary

Once the overall revenue requirements analysis was complete, the class Cost of Service (COS) analysis was prepared by Power System Engineering, Inc. This analysis is aimed at identifying the cost responsibility of each rate class and uses the same model approved by the MPUC in our 2003, 2009, and 2014 general rate cases with refinements described later in my testimony. The COS is also useful in determining the cost components of each rate class (i.e. member, energy and demand costs). The results of the class COS analysis are summarized on the following table:

Table 2
Cost of Service Summary

Rate Class	Revenue Present Rates[1]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[2]
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	113,507,080	119,475,495	5,968,415	5.29
Small General Service (41)	5,732,872	6,242,283	509,411	8.94
Irrigation (36)	917,323	892,507	(24,816)	(2.72)
General Service (46,54)	50,669,263	50,536,453	(132,811)	(0.26)
C&I Interruptible (70,71)	25,436,728	27,455,236	2,018,508	7.98
Lighting	2,079,781	2,468,469	388,689	18.79
			Total System	4.35

It is important, at this point, to distinguish between the COS and actual rate design. Due to the limitations inherent to a COS analysis, these results should be viewed as providing a general range of where rates should be. It is, in fact, uncommon for rates to be designed exactly in line with COS results.

1 Includes an allocated share of Other Operating Revenue.
2 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

Proposed Rates – Summary

Using the completed COS analysis, and in conjunction with Dakota Electric management and board of directors, we developed proposed rates. These rates are designed to meet various objectives of Dakota Electric and are discussed later in my testimony. The following table summarizes the impact of the proposed rates on Dakota Electric's rate revenue by service schedule:

Table 3
Comparison of Revenue
Present and Proposed Rates

(a)	(b)	(c)	(d)	(e)	(f)
		Revenue	**Revenue**		
Line		**Present**	**Proposed**	**Increase (Decrease)**	
No.	**Rate Class**	**Rates**	**Rates**	**Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44)	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44-4)	31,109	31,434	325	1.04
12	LED Street Lghtg Member-Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49)	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	-	-

IV. REVENUE REQUIREMENTS

Q. Please summarize the concept of revenue requirements.

A. In order to ensure financial viability, the Cooperative's retail rates must generate sufficient revenue to meet operating expenses and margin requirements. The margin requirement must in turn be adequate to cover interest expense, meet our lenders financial covenants and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) the desired equity position. In this testimony I will refer to the total operating expense and margin requirement as the "revenue requirements" of the Cooperative. This is expressed by the following equation:

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENT

To evaluate a cooperative's revenue requirement and the adequacy of its present rate structure to meet the requirement, it is common practice to analyze revenue and costs for a 12-month period of time called the Test Year.

Q. What Test Year was used to determine revenue requirements?

A. The Test Year revenue requirements for the study were based on Dakota Electric's actual historical operations for calendar year 2018, with adjustments for known and measurable changes.

Q. Has a Statement of Operations been prepared for the Test Year based on the revenue generated by DEA's present rates?

A. Yes. Exhibit__(DEA-1) provides a Statement of Operations for the Test Year based on the revenue generated by DEA's present rates.

Page 1 of Exhibit__(DEA-1) provides a summary of the Statement of Operations for the historical Test Year calendar 2018. The results shown in Column C reflect an unadjusted Test Year as actually recorded on DEA's books for the period January 1, 2018 through December 31, 2018 and correspond to the results shown in Exhibit__(DEA-2), page 1, Column C. Column D summarizes the various normalizing adjustments to the revenue and expense accounts proposed by the Cooperative with the resulting adjusted Pro Forma Test Year shown in Column E.

Page 2 of Exhibit__(DEA-1) provides a summary of each of the proposed adjustments. Pages 3 through 10 of Exhibit__(DEA-1) provide the detailed calculations for the following adjustments:

- Payroll;
- Payroll benefits;
- Depreciation;
- Other Adjustments;
- Property taxes;
- Reduction in CIP spending 2018 actual to 2019 budget;
- Regulatory filing fees;
- Rate Case filing fees recovery over 5 years; and
- Net deduction for disallowed expenses.

Page 11 of Exhibit__(DEA-1) presents the average number of consumers, energy sales, billing demand and revenue for Dakota Electric's rate classes as recorded for calendar year 2018.

Pages 12 through 21 of Exhibit__(DEA-1) present the calculation of revenue under present rates for the Pro Forma Test Year. That is, these pages multiply Pro Forma Test Year number of consumers, energy sales and billing demand times appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Dakota Electric's present tariffed fixed, energy and demand rates for various rate schedules, including the Resource and Tax Adjustment (RTA) charges and/or credits that became effective on January 1, 2019. The calculation of forecasted Test Year billing units is shown in Workpaper 13. The forecasted billing units rely on regression analysis for the residential rate class which is most sensitive to fluctuating consumption based on changing weather. For those classes that do not experience such consumption fluctuations due to weather, the Test Year billing units reflect the higher of the 2019 budgeted units or a 10-year trendline analysis.

Finally, page 22 of Exhibit__(DEA-1) presents an overview of wholesale power costs.

Q. What are Dakota Electric's Test Year revenue requirements?

A. Exhibit__(DEA-2) summarizes the operating results for DEA on both an unadjusted and an adjusted basis for the Test Year ended December 31, 2018. A summary of the Operating Statement is provided as follows:

Table 4
Statement of Operations - Present Rates

Description	2018 Actual	Pro Forma Test Year
	($)	($)
Operating Revenue	203,138,675	201,581,098
Operating Expenses[3]	197,774,614	199,769,626
Net Operating Income	5,364,061	1,811,472
Non-Operating Income		
Capital Credits	5,111,212	5,111,212
Other	292,978	292,978
Subtotal	5,404,190	5,404,190
Total Margins	10,768,251	7,215,662

[3] Before interest expense is deducted.

It should be emphasized that the Net Operating Income stated is before interest expense on long term debt is deducted.

Furthermore, it is important to distinguish between operating income or margins and total income. Use of the term "operating" is intended to designate revenue and expenses associated with the basic utility function (i.e., supplying electric distribution service to members). It is to be distinguished from Non-Operating Income, such as interest earnings from short-term investments and patronage capital credit assignments from associated organizations. Because Non-Operating Income is outside the operations and direct control of the distribution cooperative, it is not generally considered in establishing the revenue requirement for retail ratemaking purposes. Retail rates are generally designed to be sufficient, but only sufficient, to cover the operating revenue requirement.

Page 1, Column D of Exhibit__(DEA-2) shows that, in order to achieve the required ROR of 5.73 percent, present rates would need to be increased by $8,727,396 or about 4.35 percent.

Q. How was Dakota Electric's margin requirement calculated?

A. To complete the Test Year Revenue Requirement, an appropriate level of margin must be added to the previously determined operating expenses. In establishing the level of margin required to achieve the Cooperative's financial objectives, we have determined an appropriate return on rate base using a calculation methodology recommended by the Department of Commerce and approved by the Commission in our last two general rate cases.

Q. Please explain your determination of Rate of Return.

A. The Rate of Return method for establishing the Cooperative's margin requirement has been used by the Commission in Dakota Electric's general rate cases since we have been rate-regulated in the early 1980's. The ROR method is intended to ensure that earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners. When applied to cooperatives, the concept is intended to permit the development of sufficient margins to cover the cost of debt and equity capital. However, in the case of cooperatives, the term "return on equity" involves a totally different concept than it does for investor-owned utilities. Return on (or of) equity for cooperatives is related to the retirement, or rotation, of patronage capital. Thus, the ROR required for a cooperative must result in sufficient margins to:

1. Pay interest expense on long-term debt;
2. Rotate patronage capital as stated in the policy of the cooperative;
3. Maintain or achieve the desired equity position; while
4. Meeting the financial covenants of our lenders.

Q. Has the rate-based ROR approach as applied to cooperatives been endorsed by the MPUC?

A. Yes. The method was originally endorsed by the MPUC in 1976 in a case involving Anoka Electric Cooperative (Docket No. U-75-103). Since that time, it has been used in all other cases involving cooperatives, including DEA's last rate filing (Docket No. E-111/GR-14-482).

Q. Please provide an overview of Dakota Electric's Rate of Return calculation.

A. The calculations necessary to determine the Cooperative's overall Rate of Return (ROR) are shown on pages 2 through 8 of Exhibit__(DEA-2). Page 2 of Exhibit__(DEA-2) shows the calculation of the Cooperative's Rate Base, with page 3 providing the supporting detail for Materials & Supplies used in the determination of Rate Base. Page 4 summarizes Dakota Electric's loans with the National Rural Utilities Cooperative Finance Corporation (CFC), Farmer Mac, and CoBank. The Cooperative's overall cost of debt used in the Test Year is 3.77 percent. Page 5 of Exhibit__(DEA-2) reviews Dakota Electric's historic total capitalization (debt and equity) for the years 1998 through 2018. We note that the mean growth rate in historic total capitalization for 2013 through 2018 is estimated to be 3.52 percent. Page 6 of Exhibit__(DEA-2) shows the calculation of the natural logarithm asset growth rate. Dakota Electric applied the 5 year exponential growth rate in the rate of return calculation as was used in the last general rate case. The five year period encompasses near-term years with more certainty in the growth forecast and aligns with our general expectation of filing rate cases at approximately five year intervals. Page 7 of Exhibit__(DEA-2) presents various ratio calculations. Finally, page 8 of Exhibit__(DEA-2) shows the calculation of DEA's 5.73 percent proposed ROR on rate base.

Q. Please identify the input assumptions used to calculate the overall ROR on rate base.

A. The input assumptions used to calculate the overall ROR on rate base are as follows:

Asset Growth Rate	1.73%
Equity Ratio	53.085%
Debt Ratio	46.915%
Test Year Total Capital	$ 272,999,564
Test Year Total Equity	$ 173,151,167
Test Year Total Debt	$ 99,848,397
Annual Capital Credits	$ 3,500,000
Rate Base	$ 189,064,856
Cost of Long-Term Debt	3.77%

Q. Please identify the calculation for determining return on equity.

A. The calculation for determining the 4.14 percent return on equity is as follows:

$$K = g + (CC/(ER \times TC))$$

where: K = Rate of Return on Equity
g = Growth
CC = Capital Credits
ER = Equity Ratio
TC = Total Capital

Q. Please identify the calculation for determining overall cost of capital.

A. The calculation for determining the 3.97 percent overall cost of capital is as follows:

$$OCC = (ER \times K) + ((1 - ER) \times i)$$

where: OCC = Overall Cost of Capital
ER = Equity Ratio
K = Rate of Return on Equity
i = Cost of Long-Term Debt

Q. Please identify the calculation for determining overall rate of return on rate base.

A. The calculation for determining the 5.73 percent overall rate of return on rate base is as follows:

$$ROR = OCC \times (TC/RB)$$

where: ROR = Return on Rate Base
OCC = Overall Cost of Capital
TC = Total Capital
RB = Rate Base

Q. How does Rate of Return on Rate Base relate to the financial performance requirements of the Cooperative's lenders?

A. Rate of return on rate base is not a financial performance metric used by Dakota Electric's lenders.

Q. Please explain.

A. The financial performance metric used by our lenders is Modified Debt Service Coverage (MDSC). MDSC measures the number of times operating cash flow covers debt service on long-term debt. MDSC is calculated as follows:

> MDSC = (Operating Margins + Non-Operating Margins-Interest + Interest Expense + Depreciation and Amortization Expense for year + Cash received in respect of Generation and Transmission and other Capital Credits)/(All payments of principal and interest during calendar year)

For the National Rural Utilities Cooperative Finance Corporation (CFC), Dakota Electric must maintain at least a 1.35 modified debt service coverage ratio calculated as an average of the two highest, out of the most recent three years. The 1.35 MDSC is a default threshold.

For CoBank, Dakota Electric must maintain at least a 1.25 modified debt service coverage ratio each year. The 1.25 MDSC is an annual default threshold.

Q. How does the pro forma Test Year revenue requirement and proposed revenue increase translate to MDSC for the Cooperative?

A. The filed pro forma revenue requirement using the 5.73 percent calculated rate of return and proposed revenue increase results in a calculated MDSC of about 2.0.

Q. How do these results compare to the MDSC financial performance of other cooperatives?

A. Benchmark information from CFC for 1) all cooperatives in the country, 2) Minnesota cooperatives, and 3) cooperatives of similar size to Dakota Electric is as follows:

"US Total" MDSC:
- Annual 5 yr. avg. = 1.84
- 2 of 3 yr. high avg. = 1.96

Minnesota MDSC:
- Annual 5 yr. avg. = 1.69
- 2 of 3 yr. high avg. = 1.76

Similar Size Cooperative MDSC:
- Annual 5 yr. avg. = 1.99
- 2 of 3 yr. high avg. = 2.19

Dakota Electric's calculated Test Year MDSC of about 2.0 is at the average of cooperatives of similar size to Dakota Electric.

Q. Please summarize Dakota Electric's revenue requirements in this proceeding.

A. A summary of the revenue requirements is presented in Table 5. The details of these calculations are provided in Exhibit__(DEA-2).

Table 5
Revenue Requirements Summary

		($)
1.	Operating Expenses (Excluding Interest)	199,769,626
2.	Margin Requirements	
	a. Rate Base	189,064,856
	b. Rate of Return	5.73%
	c. Return Required	10,831,846
	d. Less: Non-Operating Income	292,978
	e. Net Operating Income Required	10,538,868
3.	Total Revenue Requirements	210,308,494
4.	Revenue from Present Rates	
	a. Tariff Revenue (net of RTA)	200,480,307
	b. Other Operating Revenue	1,100,791
	c. Total Revenue	201,581,098
5.	Potential Increase (Decrease)	8,727,396
	or	4.35%

Q. What level of net operating income is DEA proposing?

A. DEA has established a proposed level of net operating income (before interest expense) of about $10,539,000. The calculation of this net operating income is shown above in Table 5 and in Exhibit__(DEA-2).

Q. What overall revenue increase is DEA requesting?

A. A summary of the proposed increase is shown in the above Table 5 with detailed calculations shown in Exhibit__(DEA-2). To eliminate the present revenue deficiency, annual revenue must be increased by $8,727,396 or approximately 4.35 percent.

V. COST OF SERVICE ANALYSIS

Q. Have you prepared a Cost of Service study for Dakota Electric?

A. Yes. A class COS analysis has been prepared to provide information to be used in designing rates. The basic objective of this analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach meaning that 1) costs are allocated on an average system-wide basis, and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data and this has been confirmed by the Commission's approval of our cost of service study and methods in past rate cases.

Q. Has Dakota Electric used the same cost of service study model approved by the Commission in your last general rate case?

A. Yes, the cost of service study model is the same model approved by the Commission in our last rate case, with one modification.

Q. Please explain the modification.

A. In the Commission's final Order in Dakota Electric's 2014 general rate case in Docket No. E-111/GR-14-482, Ordering Paragraph #8 required that:

> *Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.*

In compliance with this Order, we have incorporated a demand adjustment in the minimum size method used to classify specified distribution accounts within the class cost of service study. Workpaper 21 describes the calculation of minimum size classification factors for the respective distribution accounts, identifies the analysis used to determine the relevant demand adjustment, and incorporates the demand adjustment into the minimum size methodology. These demand adjusted classification factors are then applied in the COS. For a point of reference, we have also included COS summary results based on overall classification using the zero-intercept method.

Q. Please describe Exhibit__(DEA-3).

A. Exhibit__(DEA-3) includes the COS analysis for Dakota Electric. The detailed calculations and assumptions that go into the analysis are as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-7	Adjusted Statement of Operations
8-13	Classification of Revenue Requirements
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Analysis of Class Load Characteristics
25-40	Analysis of Class Demand Characteristics
41-42	Development of Allocation Factors

NOTE: To help facilitate review of the cost of service study, Dakota Electric has prepared a "Guide to the Cost of Service Study" that is submitted as Workpaper 22. This document provides a detailed review of methods used in the COS and incorporates answers to information requests submitted by the Department of Commerce in our last several rate cases.

Q. How should the results of a COS be used?

A. It is important to recognize some of the inherent limitations of such a study. First, it must be emphasized that there are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; and not as precise values.

Second, a COS analysis is directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to their assigned consumer classification.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or “typical” data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as member acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is easily administered and understood by members.

With the above limitations in mind, a COS study can provide a useful guideline for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail members.

Q. Explain the general procedure for conducting a COS study.

A. The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

Step 1 - Classify the plant account records into basic cost causative categories.

Step 2 - Classify the Test Year expenses and margin requirement into the same cost causative categories.

Step 3 - Develop allocation factors for each rate class.

Step 4 - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

In this regard, it is important to note that Dakota Electric has used the same COS model that was approved in our last three rate cases, with a refinement to account for capacity (demand adjustment) provided by facilities identified in the minimum size method as ordered by the Commission in our last rate case.

Q. What do you mean by cost causative categories?

A. Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

1. Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.
2. Consumer - Costs that are the result of the number and location of each member and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense. In addition, a portion of distribution expenses are categorized using the results of the minimum size analysis.
3. Capacity - Costs which result from providing and maintaining operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual member service peak. Much of the expense of operating and maintaining a three phase backbone feeder would generally fall within this category as would the Demand Charge in the purchased power rate.
4. Energy - Costs which are related to the amount of energy used. The major item in this category is the Energy Charge in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	Consumer	Capacity	Energy
As Assigned		Power Supply Distribution Substation	Power Supply
	Primary Line Line Transformer Secondary & Service Meter Customer Accounting	Primary Line Line Transformer	

Q. Could you briefly explain the methodology used in assigning plant accounts to cost causative categories?

A. The cost causative classification of the various electric plant accounts is presented in pages 4 and 5 of Exhibit__(DEA-3). The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. Intangible Plant (Acct. 301 to 303) - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. Land, Structures, Station and Battery (Accts. 360 to 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. Primary Line and Devices (Accts. 364, 365, 366, 367) - Assignment of the Primary Line and Device accounts was based on results of the "Minimum Size Method" to determine the consumer component share. A narrative and calculation of the minimum size method, with a demand adjustment, is provided in Workpaper 21. The remaining amount was then assigned to the capacity component.
4. Line Transformers (Acct. 368) - Classification of the Line Transformer account was approached in similar fashion using the "Minimum Size Method" with a demand adjustment. (See Workpaper 21.) Again, it was reasoned that there exists a certain

minimum transformer investment required to provide basic service to each consumer independent of energy usage or capacity requirements. This cost is assigned to the consumer component, while the remaining investment is considered capacity related.

5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.
6. Consumer Premise (Acct. 371) - The Consumer's Premises account is associated to lighting plant and was directly assigned to the Lighting Class.
7. Street Lighting (Acct. 373) - The street or security lighting account was assigned directly to the Lighting Class.
8. General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the general plant has minimal effect on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant was not warranted.

Q. Explain how revenue requirements were classified.

A. The Operating Statement for the Test Year forms the basis for the COS analysis. Actual expenses by account for the historical 12-month period were used to establish the pattern of the Test Year cost breakdown to the various accounts.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 8 through 13 of Exhibit__(DEA-3). The factors used in the expense classification are summarized in pages 14 through 17 of Exhibit__(DEA-3). The methodology and rationale for that methodology is discussed below:

1. Purchased Power (Acct. 555) - The Demand and Energy Charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively. This includes Transmission Charges which were assigned to the capacity component.
2. Distribution Operation and Maintenance (Accts. 580 - 598) - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 587, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
3. Consumer Accounting (Accts. 901 - 905) - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
4. Consumer Service and Information and Sales (Accts. 907 - 916) - Consumer Service and Information and Sales expenses are also considered consumer related expenses.
5. Administrative and General (Accts. 920 - 932) - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Thus, we have assigned 10 percent of these expenses to the

power supply function and the remainder in proportion to the total of all other expenses without power supply.

6. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the net plant account assignments.
7. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the net plant account assignments.
8. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
9. Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense and return on equity, both related to plant investment, it is reasonable to classify this cost in proportion to the net plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., rate base - ROR method).

Q. Discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented in pages 20 to 22 of Exhibit__(DEA-3). The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation

   Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.
2. Consumer Costs Allocations

   Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of Exhibit__(DEA-3) to recognize the higher cost of three phase service versus standard single phase service for each subcategory of consumer related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay at least a token portion of the consumer related expense, hence the 0.02 weighting factor.

3. Capacity Cost Allocations

Three different allocation factors were developed for the capacity component. (See pages 24 to 40 of Exhibit__(DEA-3) for the development of class demands):

a. Line transformer capacity related costs were allocated in accordance with the estimated undiversified non-coincidental annual peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

b. Distribution Substation and Primary Line capacity costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased Power Demand Charges were allocated in accordance with the average monthly coincidental class demands established by season.

d. Purchased Power Transmission Charges were allocated in accordance with the average monthly coincidental class demands

4. Energy Cost Allocations

Energy related costs were allocated on the basis of total energy sales in each rate class and further segmented into on-peak and off-peak energy.

Allocation factors for each category are developed in pages 41 to 42 of Exhibit__(DEA-3).

Q. Please summarize the results of the COS study performed for Dakota Electric.

A. Results obtained from the COS analysis are summarized in Tables 6, 7 and 8. Table 6 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 6 **Cost of Service Summary**				
Rate Class	**Revenue Present Rates[4]**	**Revenue Requirement**	**Increase (Decrease)**	
			Amount	**Percent[5]**
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	113,507,080	119,475,495	5,968,415	5.29
Small General Service (41)	5,732,872	6,242,283	509,411	8.94
Irrigation (36)	917,323	892,507	(24,816)	(2.72)
General Service (46,54)	50,669,263	50,536,453	(132,811)	(0.26)
C&I Interruptible (70,71)	25,436,728	27,455,236	2,018,508	7.98
Lighting	2,079,781	2,468,469	388,689	18.79
			Total System	4.35

Table 7 shows a breakdown of the COS by cost category for each class.

Table 7 **Cost Allocation Summary**				
Rate Class	**Cost Category**			
	Power Supply	**Transmission**	**Distribution**	**Total**
	($)	($)	($)	($)
Residential & Farm (31,32,53)	65,457,456	13,696,762	40,321,277	119,475,495
Small General Service (41)	3,298,400	706,106	2,237,776	6,242,283
Irrigation (36)	447,438	12,511	432,558	892,507
General Service (46,54)	36,036,904	7,229,676	7,269,873	50,536,453
Interruptible Service (70,71)	21,738,992	880,227	4,836,017	27,455,236
Street and Security Lighting	667,425	124,341	1,676,703	2,468,469
Total	127,646,615	22,649,623	56,774,205	207,070,443

4 Includes an allocated share of Other Operating Revenue.
5 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

Table 8 provides total costs by class expressed in terms of $ per customer per month (consumer component) and ¢ per kWh (capacity and energy components).

Table 8
Unit Cost Summary

Rate Class	Consumer Unit Cost	Demand Unit Cost	Energy Unit Cost
	($/cust.mo.)	(¢/kWh)	(¢/kWh)
Residential & Farm (31,32,53)	25.11	5.34	5.30
Small General Service (41)	32.65	5.29	5.30
Irrigation (36)	57.31	2.52	5.30
General Service (46,54)	60.71	5.18	5.30
Interruptible Service (70,71)	221.08	1.27	5.30
Street and Security Lighting	0.50	3.96	4.93

VI. OTHER COST ANALYSES

Q. Is any other cost analysis included in this filing besides the class COS study?

A. Yes, several other cost analyses are included in my exhibits as follows:

Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU Analysis –Schedule 56

Q. Please explain the load management cost analysis.

A. The load management cost analysis, shown in Exhibit__(DEA-4), presents the costs to provide service to Schedules 49, 51, and 52. These costs include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. In the case of storage service, the cost is calculated at 4.87¢ per kWh, while the cost for interruptible service is 6.31¢ per kWh. The cost for geothermal heat pump service is calculated at 11.07¢ per kWh. This cost analysis will form the basis for rate recommendations for Schedules 49, 51 and 52 described later in my testimony.

Q. Explain the exhibit that calculates monthly fixed charge costs.

A. Exhibit__(DEA-7) calculates the monthly costs that should be applied in the monthly fixed charge of retail rates. This exhibit first identifies the "customer" related costs allocated to each class in the cost of service study. While such costs have been allocated based on number of consumers, not all of these costs may be appropriate for recovery in the monthly fixed charge. As Dakota Electric testified in our last general rate cases, we believe it is appropriate for the monthly fixed charge to recover costs we incur to stand ready to provide electric service, excluding costs for primary line. Such costs to be included in the monthly fixed charge include the monthly cost of a transformer, meter and service, customer accounting, as well as taxes and margin associated with plant costs proposed for recovery in the monthly fixed charge. The monthly fixed costs identified for recovery in this analysis are as follows:

Residential	$15.01
Small General	$20.32
Irrigation	$41.19
General	$44.99
C&I Interruptible	$200.69

This cost analysis will form the basis for rate recommendations described later in my testimony.

Q. Discuss the calculation of Coincidental Demand Charges shown in Exhibit__(DEA-8).

A. The calculation of Coincidental Demand Charges reflects the wholesale demand-related charges Dakota Electric experiences from Great River Energy adjusted for distribution line loss. These calculations allow us to determine the summer, winter and other months' retail Coincident Demand Charges for the partial interruptible option and full interruptible option for Dakota Electric's Schedules 70 and 71.

Q. Explain the analysis for special fees and charges.

A. Exhibit__(DEA-10) presents an analysis of Dakota Electric's costs associated with special fees and charges. This exhibit calculates the labor, benefits, vehicles and other expenses associated with each special fee and charge. The results of this analysis will be used to update Dakota Electric's special fees and charges.

Q. Explain the line extension analysis.

A. Exhibit__(DEA-11) presents the costs of actual line extension project costs and charges. This exhibit also identifies the amount of plant investment Dakota Electric recovers through base rates for these line extensions. The plant investment amounts on a per kWh and per kW basis from this exhibit will be applied to commercial line extensions.

Looking at recovery for individual residential line extensions, Exhibit__(DEA-11) shows that Dakota Electric's base rates for residential members recover about $1,300 of distribution plant costs per residential member. By comparison, the average cost for extensions to individual residential members with no footage (includes material, labor, and vehicle costs to set a transformer and make the electrical connection) is about $3,600. To recover these basic extension costs, Dakota Electric proposes to increase the present flat fee for all individual residential extensions from $500 to $1,000. For new connections where the extension of cable is also required, Dakota Electric proposes to increase the present charge of $8.30 per foot to $11.00 per foot. These changes will also eliminate the application of a free footage allowance. This flat fee increase will provide additional revenue to cover more of the fixed costs associated with transformer and connection costs not otherwise recovered in base rates. We note that while these line extension costs are proposed to increase, the amount of increase is still below our extension costs not being recovered in base rates. Dakota Electric anticipates making continued incremental increases to individual residential line extension provisions in future rate case proceedings.

Q. Have you calculated new base factors for Dakota Electric's Resource & Tax Adjustment (RTA)?

A. Yes. Exhibit__(DEA-12) presents the calculation of RTA base components for cost of power, conservation and DSM expenditures, and property tax recovery. These new base components will be applied with the implementation of final rates.

Q. Please describe the calculation of power cost bases.

A. We have calculated several different power cost bases that track differences in wholesale power costs associated with specific retail rates. The calculation begins with an identification of an Energy Cost Adjustment (ECA) base. This ECA base relates to retail interruptible service that Dakota Electric provides to C & I members under interruptible service Schedules 70 and 71. This ECA base also applies to interruptible irrigation service provided under Schedule 36. (We note that firm irrigation service under Schedule 36 will be subject to the firm Power Cost Adjustment (PCA) base as described below.) The average wholesale energy cost per kWh applicable to the Energy Cost Adjustment base equals $0.0521 per kWh sold.

The next part of this exhibit calculates weighted power cost bases for Dakota Electric's load management rates including Schedules 51 and 52. For each rate schedule, we have calculated a weighted average wholesale power cost reflecting the relative purchase of water heating and space heating service under each schedule. Schedule 51 has a weighted power cost base per kWh sold of $0.0204. Schedule 52 has a weighted power cost base per kWh sold of $0.0352.

Next, we calculate the power cost base for rate Schedule 49, geothermal service. The base for this service includes the Cooperative's system average wholesale cost for energy, capacity, transmission, and ancillary service cost on a per kWh basis. The resulting Schedule 49 power cost base per kWh sold is $0.0813.

Finally, this exhibit calculates the Power Cost Adjustment (PCA) base applicable to Dakota Electric's remaining firm service rate schedules. This calculation begins with the Cooperative's total wholesale power cost, from which we subtract ECA power costs, Rate 51 power costs, Rate 52 power costs, Rate 49 power costs, and wholesale power cost pass-throughs for Wellspring, Member Specific Discount, Large Load High Load Factor Credit, Contract Rate Service, and Standby service. The result is a PCA base per kWh sold for Dakota Electric's firm service rate schedules of $0.0939.

Q. Explain the exhibit that evaluates cycled air conditioning.

A. Exhibit__(DEA-13) calculates the wholesale power cost savings achieved through cycling central air conditioners. Dakota Electric's cycled air conditioning program, in coordination with Great River Energy, provides for load control of central air conditioners typically during times of high demand. Air conditioners are controlled, or cycled, through fifteen minute on and fifteen minute off cycles during the respective control period. This exhibit calculates a diversified demand reduction for a typical controlled air conditioning unit. Based on this analysis, Dakota Electric recommends maintaining the present $13.00 per month <u>credit</u> in the months of June, July, and August, with a corresponding increase in the energy credit for those units that are separately metered and an increase in the per ton credit for commercial units.

Q. Please explain the Standby Analysis.

A. Exhibit__(DEA-14) calculates the primary and secondary distribution reservation fees for Standby Service. These costs are based on allocated costs to Dakota Electric's General

Service Schedule 46, which corresponds to the size and type of customers who would likely receive such standby service. In fact, the one standby member that Dakota Electric serves is of a size that would normally receive service under Schedule 46. This exhibit also updates the substation standby reservation fee consist with the methodology approved by the Commission when Dakota Electric proposed this fee in Docket No. E-999/CI-15-115.

Q. Please explain the Electric Vehicle Rate Analysis.

A. Exhibit__(DEA-15) updates the cost analysis that Dakota Electric submitted to the Commission when we proposed this service. The update reflects Test Year wholesale power supply and distribution costs. This rate has been very well received by members with electric vehicles, as we reported in a May 31, 2019, EV Informational Letter to the Commission. Based on participation and the high level of off-peak charging, Dakota Electric proposes to remove the "pilot" designation for this rate.

Q. Please explain the Residential TOU Analysis for Schedule 56.

A. Exhibit__(DEA-16) presents an analysis of costs and development of rate design for the residential time of use rate (Schedule 56) that was approved in our last rate case. Page 1 of this exhibit identifies wholesale power and distribution costs based on the cost of service study results for the residential class. Page 2 assigns these costs to respective cost components and time periods. Page 3 estimates billing units, on a total residential class basis, for the billing periods for this schedule. Finally, page 4 develops rates for each billing component using the cost assignments from page 2.

VII. RATE DESIGN

Various tables showing the results of the COS analysis are useful in discussing the design and evaluation of Dakota Electric's rates. These tables, which have been previously presented, are listed below:

Table	Description
Table 6	Cost of Service Summary
Table 7	Cost Allocation Summary
Table 8	Unit Cost Summary

Q. What objectives have you considered while developing proposed rate changes?

A. There are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.
6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the Cooperative must be made.

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as 1) the need to avoid abrupt changes and 2) the desire to achieve member-consumer acceptance also came into play. Thus, the dollar and percentage increase or decrease for each class as shown in Table 6 were tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Summarize the revenue impact of your proposed rates.

A. The rate design recommendations for the rate schedules contained and discussed herein result in an approximate $8,700,000 revenue increase. (We note that additional annual revenue will be provided by proposed changes to special fees and charges and from residential line extensions.) Table 9 presents a comparison of the Present and Proposed Rates by service schedule.

Table 9
Comparison of Revenue
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates ($)	(d) Revenue Proposed Rates ($)	(e) Increase (Decrease) Amount ($)	(f) Increase (Decrease) Percent (%)
1	Residential & Farm Service (31)	114,332,035	119,389,671	5,057,636	4.42
2	Residential & Farm Demand Control (32)	42,670	44,529	1,859	4.36
3	Electric Vehicle (33)	24,636	26,505	1,869	7.59
4	Irrigation Service (36) Firm	50,143	50,484	341	0.68
5	Irrigation Service (36) Interruptible	862,089	883,153	21,064	2.44
6	Small General Service (41)	5,799,609	6,197,337	397,728	6.86
7	Security Lighting Service (44)	102,369	120,526	18,157	17.74
8	Street Lighting Service (44-2)	466,293	524,779	58,486	12.54
9	Street Lighting System (44-1)	72,603	88,142	15,539	21.40
10	Custom Residential Street Lighting (44-3)	1,334,683	1,623,968	289,285	21.67
11	LED Security Lighting Service (44-4)	31,109	31,434	325	1.04
12	LED Street Lghtg Member-Owned(44-5)	1,297	1,473	176	13.57
13	LED Street Lighting (44-6)	59,884	57,768	(2,116)	(3.53)
14	Low Wattage Unmetered Service (45)	8,520	8,946	426	5.00
15	General Service (46)	50,261,766	51,183,966	922,200	1.83
16	Municipal Civil Defense Sirens (47)	3,960	3,960	-	-
17	Geothermal Heat Pump (49)	16,571	17,798	1,227	7.40
18	Controlled Energy Storage (51)	459,736	502,001	42,265	9.19
19	Controlled Interruptible Service (52)	2,634,418	2,784,452	150,034	5.70
20	Residential & Farm Time of Day (53)	29,057	30,323	1,266	4.36
21	General Service Time of Day (54)	126,286	130,543	4,257	3.37
22	Standby Service (60)	66,840	74,160	7,320	10.95
23	Full Interruptible Service (70)	23,144,467	24,654,929	1,510,462	6.53
24	Partial Interruptible Service (71)	2,151,089	2,299,459	148,370	6.90
25	Cycled Air Conditioning Service (80)	(1,625,193)	(1,625,193)	-	-

Q. Provide an overview of your approach to proposed changes in monthly fixed charges.

A. Exhibit__(DEA-7) identifies the cost basis for the proposed monthly fixed charges and was described above. Using these results and recognizing the historic difficulty of increasing this billing component, Dakota Electric proposes to increase the monthly fixed charge for residential service and small general service by $1 per month. This is the amount that was approved in prior rate cases after considerable testimony. For the other rate schedules, we propose aligning the monthly fixed charge on a similar cost basis percentage as the residential monthly fixed charge. The proposed monthly fixed charge changes 1) provide a more appropriate recovery of costs through this rate component, 2) reduce the amount of such costs that are otherwise recovered in volumetric charges, 3) align with similar charges the Commission has approved for neighboring utilities, and 4) make some progress toward cost recovery of this component in this rate case. We note, however, that this modest increase in the monthly fixed charge could result in taking 20 years or more to reach the appropriate cost recovery level for this component – based on the more recent approximate five-year cycle for Dakota Electric rate cases.

Q. Please describe the proposed rates.

A. A discussion of each of the proposed rates follows:

Residential & Farm Service (31)

The COS study shows the need to increase revenue from Residential & Farm (Schedules 31, 32 and 53) of about $5,968,000 or a 5.29 percent increase (see Table 6) over revenue from present rates. Dakota Electric is proposing a slightly lower increase for residential members. We propose to increase the monthly fixed charge from the present $9.00 to $10.00. The present summer Energy Charge of $0.1308 per kWh ($0.1333 per kWh including the RTA) is proposed to increase to $0.1379 per kWh for the summer months of June, July and August. The proposed Energy Charge for all other months will increase from $0.1168 per kWh ($0.1193 per kWh including the RTA) to $0.1239 per kWh. These proposed rates reflecting a “zeroing” of the present RTA and result in an increase to the Schedule 31 class of approximately 4.42 percent.

Table 10 Comparison of Present and Proposed Residential & Farm Service (31)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$9.00/month	$10.00 /month
Energy Charge		
Summer Months	$0.1308/kWh	$0.1379/kWh
Other Months	$0.1168/kWh	$0.1239/kWh
Average Charge		
RTA Charge	$0.0025/kWh	$0.0000/kWh

Dakota Electric is also proposing clarifying language to the Schedule 31 "Availability" clause and the addition of a clause describing billing for master-metered multi-tenant residential facilities. Both of these additions relate to the cost of service study and language we added to the to Schedule 31 related to service to apartments. The clarifying language proposed for the Availability clause indicates that Schedule 31 applies "to individually metered apartment units and mastered-metered multi-tenant complexes." This was the intent of the application that was adopted in our 2003 general rate case. It is reasonable for apartment units and apartment complexes to be billed under Schedule 31 since these are residential loads with residential load profiles. The new clause "Billing for Master-Metered Multi-Tenant Residential Facilities" specifies that "The monthly bill for master-metered multi-tenant residential facilities will be determined by multiplying the number of residential living units per master-meter times the Fixed Charge plus the metered energy consumption times the applicable energy charge plus the Resource and Tax Adjustment."

Residential & Farm Demand Control (32)

As previously noted, the COS study generally shows a required revenue increase from Residential members of about 5.29 percent. Accordingly, we recommend that the monthly Fixed Charge be increased from $12.00 to $13.00. We further propose to continue the seasonality in this rate structure through the Demand Charge by increasing the summer

Demand Charge from $14.70 per kW per month to $15.50 and the demand rate for all other months from $11.10 per kW to $11.90 per kW. We propose to increase the Energy Charge from the present tariff amount of $0.0760 per kWh ($0.0785 per kWh including the RTA) to $0.0810 per kWh. These proposed rates result in a revenue increase of about 4.36 percent for this rate schedule.

Table 11
Comparison of Present and Proposed
Residential & Farm Demand Control (32)

Description	Present Rate	Proposed Rate
Fixed Charge	$12.00/month	$13.00/month
Demand Charge		
Summer Months	$14.70/kW	$15.50 /kW
Other Months	$11.10/kW	$11.90/kW
Energy Charge	$0.0760/kWh	$0.0810/kWh
Average Charge		
RTA Charge	$0.0025	$0.0000

Electric Vehicle - Residential (33)

Dakota Electric received Commission approval to implement a pilot residential electric vehicle service in Docket No. E-111/M-12-874. This service (also referred to as Schedule EV-1) provides our residential members with an additional option for charging the batteries in their electric vehicle. Dakota Electric proposes to remove the "pilot" designation for this schedule and update the rates for this service based on the Test Year wholesale power and distribution cost analysis in Exhibit__(DEA-15). The comparison of present and proposed rates is shown in Table 12 below.

Table 12 Comparison of Present and Proposed Residential Electric Vehicle Service (33)		
Description	**Present Rate**	**Proposed Rate**
Energy Charges:		
Off-Peak	$0.0674/kWh	$0.0756/kWh
On-Peak	$0.4144/kWh	$0.4421/kWh
Other	Schedule 31	Schedule 31
RTA Charge	$0.0025/kWh	$0.0000/kWh

Irrigation Service (36)

The cost of service study shows the need to reduce revenues from irrigation service by about $25,000 or about 2.72%. However, to accommodate overall rate moderation among classes and to maintain relationships between similar billing components in other schedules, we propose a modest revenue increase for irrigation. The firm service irrigation rate structure presently includes a monthly fixed charge of $30 per month that is applied every month throughout the calendar year. We propose keeping this monthly fixed charge at $30 per month. The seasonal component for this firm service is incorporated in the Demand Charge with a present summer month Demand Charge of $26.35 which we propose to increase to $26.60. The $20.95 per kW per month Demand Charge in the winter months is proposed to increase to $21.20 per kW, and the $15.50 per kW Demand Charge in the spring and fall months is proposed to increase to $15.67 per kW. The present Energy Charge of $0.0499 per kWh ($0.0524 per kWh including the RTA) for all energy consumed throughout the year is proposed to change to $0.0521 per kWh.

Like the firm irrigation rate, the controlled irrigation rate will include a monthly fixed charge of $30.00 per month that will be applied during all months throughout the calendar year. Dakota Electric proposes no change in the present $4.55 per kW demand charge that recover distribution costs. (Since there is no seasonality in the wholesale power cost associated with controlled irrigation, the controlled irrigation rate does not incorporate any seasonality.) Finally, the proposed energy rate for controlled irrigation service will be the same $0.0521 per kWh proposed for firm irrigation service.

Table 13
Comparison of Present and Proposed
Firm Irrigation Service (36)

Firm Service		Present	Proposed
Fixed Charge	@	$30.00/month	$30.00 /month
Demand Charge			
Summer	@	$26.35/ kW/month	$26.60/kW/month
Winter	@	$20.95/ kW/month	$21.20 /kW/month
Other	@	$15.50/ kW/month	$15.67/kW/month
Energy Charge	@	$0.0499/kWh	$0.0521/kWh
RTA Charge	@	$0.0025/kWh	$0.0000/kWh

Table 14
Comparison of Present and Proposed
Interruptible Irrigation Service (36)

Interruptible Service		Present	Proposed
Fixed Charge	@	$30.00/month	$30.00 /month
Demand Charge	@	$4.55/ kW/month	$4.55/kW/month
Energy Charge	@	$0.0499/kWh	$0.0521/kWh
RTA Charge	@	($0.0005)/kWh	$0.0000/kWh

Small General Service (41)

The COS study shows the need to increase revenues from the Small General Service class in the amount of $509,000 or 8.94 percent. Dakota Electric proposes a more moderate overall revenue increase accomplished by increasing the monthly Fixed Charge for Small General Service from the present $14.00 per month to $15.00 per month. The present Energy Charge of $0.1269 per kWh ($0.1294 per kWh including the RTA) in the summer months of June, July and August is proposed to increase to $0.1375 per kWh and the present and the $0.1129 per kWh ($0.1154 per kWh including the RTA) Energy Charge during all other months is proposed to increase to $0.1235 per kWh. These proposed rates result in a revenue increase of about 6.86 percent for this rate schedule.

Table 15
Comparison of Present and Proposed
Small General Service (41)

Description	Present Rate	Proposed Rate
Fixed Charge	$14.00/month	$15.00/month
Energy Charge		
Summer Months	$0.1269/kWh	$0.1375/kWh
Other Months	$0.1129/kWh	$0.1235/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

General Service (46)

While the cost of service study shows a decrease of about 0.26 percent is justified for the General Service rate schedule, we are proposing a modest increase in revenue from this rate schedule to balance revenue from other classes.

The present General Service Schedule 46 includes a monthly Fixed Charge of $34.00, which we propose to keep at the same amount. The Demand Charge in the summer months of June, July and August is proposed to increase from $12.26 per kW to $13.70 per kW.

The Demand Charge during the remaining months is proposed to increase from $9.16 per kW to $10.60 per kW. These demand rate changes make progress in aligning demand charges with underlying capacity costs of providing service.

The proposed Energy Charges reflect load characteristics of customers on a monthly basis. This energy structure, commonly referred to as an "hours-use demand rate," is based on the amount of energy that an individual member uses each month <u>in relation</u> to the member's monthly non-coincident demand. That is, this energy rate is load-factor sensitive. The present energy rate for the first 200 kWh of energy consumption per kW of demand is $0.0776 per kWh ($0.0801 per kWh including the RTA) and is proposed to stay at $0.0776 per kWh. The next 200 kWh of energy consumption per kW of demand presently at $0.0676 per kWh ($0.0701 per kWh including the RTA) is proposed to stay at $0.0676 per kWh. All energy consumption above 400 kWh per kW of demand presently at $0.0576 per kWh ($0.0601 per kWh including the RTA) is proposed to stay at $0.0576 per kWh. Dakota Electric will continue to offer primary voltage discounts for members presently receiving primary service. The proposed General Service Schedule 46 rates result in an annual revenue increase of about 1.83 percent.

Table 16
Comparison of Present and Proposed
General Service (46) Rates

Description	Present Rate	Proposed Rate
Fixed Charge	$34.00/month	$34.00/month
Demand Charge		
Summer Months	$12.26 /kWh	$13.70 /kWh
Other Months	$9.16 /kWh	$10.60 /kWh
Energy Charge		
First 200 kWh/kW	$0.0776/kWh	$0.0776/kWh
Next 200 kWh/kW	$0.0676/kWh	$0.0676/kWh
Over 400 kWh/kW	$0.0576/kWh	$0.0576/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh
Discounts		
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%

Dakota Electric is also proposing two additions to billing provisions for Schedule 46. The first addition relates to the determination of billing demand. Prior to our 2003 general rate case, Dakota Electric had a provision in our general service rates that limited the billing impact for low load factor accounts. This provision was eliminated in the 2003 rate case and we find that it is reasonable and necessary to reintroduce a similar provision. Dakota Electric proposes to add language to the renamed "Determination of Demand" clause as follows: "In no month shall the Billing Demand be greater than the value in kW determined by dividing the kWh sales for the billing month by the product of 24 hours x 0.1 load factor x days in the billing month." Such a load factor billing limitation is reasonable since low load factor consumers generally exhibit lower system coincidence (distribution and wholesale power) than average consumers in the class.

The second addition relates to a proposed new clause describing billing for multi-use facilities. Multi-use facilities are properties that include a combination of commercial or institutional load along with some portion of residential domestic consumption. A growing example of this type of facility would be a property with independent living/apartment units where tenants may transfer to a unit with nursing or hospital type care. This could also include facilities with combined retail and residential living. The intent of this new clause is to provide clarification on billing for these facilities. Where electric service is provided through a single meter, the billing would be under either Schedules 41, 46 or 54. Where metering is separated between residential and commercial consumption, the service would be billed under Schedule 31 and Schedules 41/46/54 respectively.

Lighting Service (Rates 44, 44-1, 44-2, 44-3, 44-4, 44-5, 44-6)

The COS shows a need to increase lighting revenue by about 18.79 percent. This is a substantial increase. To ease this impact on members with lighting service, Dakota Electric proposes to implement this increase over the course of three years. (Dakota Electric took a similar approach in our 2003 rate case when implementing a higher increase for irrigation service.) Dakota Electric proposes the following three-year phase-in of lighting rates:

Table 17
Comparison of Present and Proposed
Rates for Lighting Service

Description	Present Rate per Month	Year 1 Rate per Month	Year 2 Rate per Month	Year 3 Rate per Month
Security Lighting Service (44)				
100 W HPS	$ 10.10	$ 10.74	$ 11.37	$ 12.01
150 W HPS	$ 11.99	$ 12.75	$ 13.50	$ 14.26
250 W HPS	$ 15.79	$ 16.80	$ 17.82	$ 18.83
Street Lighting Service (44-1)				
175 W MV	$ 10.52	$ 11.43	$ 12.34	$ 13.25
250 W MV	$ 13.46	$ 14.55	$ 15.65	$ 16.74
400 W MV	$ 18.54	$ 19.93	$ 21.32	$ 22.71
100 W HPS	$ 7.56	$ 8.24	$ 8.93	$ 9.61
150 W HPS	$ 9.46	$ 10.23	$ 11.01	$ 11.78
200 W HPS	$ 11.41	$ 12.33	$ 13.26	$ 14.18
250 W HPS	$ 13.25	$ 14.28	$ 15.32	$ 16.35
400 W HPS	$ 17.67	$ 18.86	$ 20.05	$ 21.24

Street Lighting Service (44-2)								
175 W MV	$	15.23	$	15.97	$	16.70	$	17.44
250 W MV	$	18.16	$	19.08	$	20.01	$	20.93
400 W MV	$	23.25	$	24.46	$	25.68	$	26.89
100 W HPS	$	12.27	$	12.78	$	13.29	$	13.80
150 W HPS	$	14.16	$	14.76	$	15.37	$	15.97
250 W HPS	$	17.95	$	18.81	$	19.68	$	20.54
400 W HPS	$	22.38	$	23.39	$	24.41	$	25.42
Custom residential Lighting (44-3)								
175 W MV	$	11.37	$	12.26	$	13.14	$	14.03
50 W HPS	$	6.70	$	7.28	$	7.87	$	8.45
100 W HPS	$	8.41	$	9.07	$	9.73	$	10.39
150 W HPS	$	10.30	$	11.08	$	11.85	$	12.63
250 W HPS	$	14.09	$	15.13	$	16.17	$	17.21
LED Security Lighting Service (44-4)								
LED (>4,500 lumens)	$	7.63	$	7.67	$	7.71	$	7.75
LED Street Lighting (44-5)								
A (40 – 80 watts)	$	4.81	$	5.04	$	5.27	$	5.50
B (81 – 150 watts)	$	6.71	$	7.06	$	7.40	$	7.75
C (151 – 250 watts)	$	9.66	$	10.16	$	10.66	$	11.16
D (251 – 350 watts)	$	13.05	$	13.71	$	14.38	$	15.04
E (351 – 450 watts)	$	16.52	$	17.37	$	18.22	$	19.07
LED Street Lighting "Standard" (44-6)								
Coach	$	10.60	$	10.17	$	9.73	$	9.30
Acorn	$	11.24	$	11.11	$	10.98	$	10.85
Cobra	$	8.31	$	8.41	$	8.50	$	8.60
Shoebox	$	10.71	$	10.71	$	10.70	$	10.70
LED Street Lighting "Basic" (44-6)								
Coach	$	6.83	$	6.67	$	6.52	$	6.36
Acorn	$	6.30	$	6.24	$	6.18	$	6.12
Cobra	$	6.51	$	6.67	$	6.82	$	6.98
Shoebox	$	7.98	$	8.21	$	8.45	$	8.68

Low Wattage Unmetered Service (45)

Dakota Electric proposes to increase the Low Wattage Unmetered Service Schedule 45 rate from $10.00 per month to $10.50 per month.

Table 18
Comparison of Present and Proposed
Low Wattage Unmetered Service (45)

Description	Present Rate	Proposed Rate
Fixed Charge	$10.00/month	$10.50/month

Municipal Civil Defense Sirens (47)

Dakota Electric is not proposing any changes in the monthly $5.00 fixed charge applicable to Municipal Civil Defense Sirens.

Table 19
Comparison of Present and Proposed
Municipal Civil Defense Sirens (47)

Description	Present Rate	Proposed Rate
Fixed Charge	$5.00/month	$5.00/month

Geothermal Heat Pump (49)

Dakota Electric's cost analysis for the Geothermal Heat Pump Rate is shown in Exhibit__(DEA-4). The costs for Schedule 49 include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. The cost for geothermal heat pump service is calculated at $0.1107 per kWh. We propose an increase in the energy charge for this service from the present tariffed rate of $0.0940 per kWh ($0.0959 per kWh including the RTA) to $0.103 per kWh. Since geothermal heat pump service is no longer offered as a special program rate through our wholesale power supplier, this service been closed to new members since our last rate case.

Controlled Energy Storage (51)

Dakota Electric's cost analysis for Controlled Energy Storage is shown in Exhibit__(DEA-4). The cost for Controlled Energy Storage service is calculated at $0.0487 per kWh. We propose an increase in the Energy Charge for this service from the present $0.0440 per kWh ($0.0446 per kWh including the RTA) to $0.0487 per kWh. This represents an increase of approximately 9.19 percent for this service.

Table 20
Comparison of Present and Proposed
Controlled Energy Storage (51)

Description	Present Rate	Proposed Rate
Net Energy Charge	$0.0440/kWh	$0.0487/kWh

Controlled Interruptible Service (52)

A cost analysis for Controlled Interruptible Service is shown in Exhibit__(DEA-4). The cost for Controlled Interruptible service is calculated at $0.0631 per kWh. Dakota Electric proposes an increase in the rate for this service from the present energy rate of $0.0550 per kWh ($0.0597 per kWh including the RTA) to a proposed energy rate of $0.0631 per kWh. This represents a 5.7 percent increase.

Table 21
Comparison of Present and Proposed
Controlled Interruptible Service (52)

Description	Present Rate	Proposed Rate
Net Energy Charge	$0.0550/kWh	$0.0631/kWh

Residential & Farm Time of Day (53)

The COS for Residential & Farm Time of Day service was incorporated in the COS study with the Residential & Farm Service Schedule 31. Since the COS for these classes is similar, we are proposing a similar revenue increase for Schedule 53. This revenue increase will be achieved by increasing the monthly Fixed Charge from the present $12.00 to $13.00. The present summer Peak Period Energy Charge of $0.1880 per kWh ($0.1905 per kWh including the RTA) will be increased to $0.21263 per kWh and the present other months Peak Period Energy Charge of $0.1740 per kWh ($0.1765 per kWh including the RTA) will be increased to $0.19863 per kWh. The Off-Peak Energy Charge will be changed from $0.0940 per kWh ($0.0965 per kWh including the RTA) to $0.09450 per kWh. These proposed changes result in an overall increase of about 4.36 percent.

Table 22
Comparison of Present and Proposed
Residential & Farm Time of Day (53)

Description	Present Rate	Proposed Rate
Fixed Charge	$12.00/month	$13.00/month
Energy Charges		
Peak Period:		
Summer	$0.1880/kWh	$0.21263/kWh
Other	$0.1740/kWh	$0.19863/kWh
Off-Peak	$0.0940/kWh	$0.09450/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

General Service Time of Day (54)

Dakota Electric proposes to realign component rates for Schedule 54 to track changes to other similar rate schedules. We propose to keep the monthly Fixed Charge for Rate 54 at the present $36.00. The Peak Period Demand Charge will be changed to $26.14 per kW in the summer months (June, July and August), $19.91 per kW in the winter months (December, January and February) and $13.67 per kW during all other months. The Maximum Demand Charge of $4.75 per kW will be increased to $5.25 per kW. The Energy Charge of $0.0499 per kWh ($0.0524 per kWh including the RTA) will be changed to $0.0521 per kWh. This proposed rate design results in a revenue increase of about 3.37 percent for this rate schedule.

Table 23 Comparison of Present and Proposed General Service Time of Day Service (54)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$36.00/month	$36.00/month
Demand Charges		
Peak Period:		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Maximum	$4.75/kW	$5.25 /kW
Energy Charge	$0.0499/kWh	$0.0521 /kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0025/kWh	$0.0000/kWh

Residential & Farm Time of Day (56)

(NOTE: *This service was originally identified as Schedule 55 when it was first proposed in our last general rate case. During that proceeding, we realized that the "55" code was already being used internally – so the final approved designation for this service is Schedule 56.*)

The cost analysis and development of the proposed rates for the Residential & Farm Time of Day service is detailed in Exhibit 16. Table 31 identifies the proposed charges for this service.

Table 24 Comparison of Present and Proposed Residential & Farm Time of Day (56)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$12.00/month	$13.00/month
Energy Charges		
Peak Periods:		
Summer	$0.2710/kWh	$0.2890/kWh
Winter	$0.2210/kWh	$0.2320/kWh
Other	$0.1750/kWh	$0.1880/kWh
Intermediate	$0.0970/kWh	$0.1060/kWh
Off-Peak	$0.0760/kWh	$0.0820/kWh
RTA Charge	$0.0025/kWh	$0.0000/kWh

Standby Service (60)

The distribution reservation fees for standby service have been analyzed in the attached Exhibit__(DEA-14). This analysis reflects the average primary and secondary distribution costs on a per kW basis for our General Service Schedule 46 members. It also updates the substation standby reservation fee consist with the methodology approved by the Commission when Dakota Electric proposed this fee in Docket No. E-999/CI-15-115. Based on this analysis, we propose increasing the primary distribution reservation fee from $3.28 per kW to $3.89 per kW. The secondary distribution reservation fee is proposed to increase from $3.51 per kW to $4.02 per kW. The substation distribution reservation fee is proposed to decrease from $0.90 per kW to $0.81 per kW. The generation reservation fees for this service are a direct passthrough of such wholesale power standby reservation fees from Great River Energy and are updated annually as authorized in this schedule.

Interruptible Service - Full Interruptible Option (70)

The cost of service study shows a need to increase revenue from the C & I interruptible members by about 7.98 percent. We propose a more moderate revenue increase. We propose increasing the monthly Fixed Charge from $110.00 to $130.00 per month. Coincidental Demand Charges are proposed at $26.14 per kW in the summer months, $19.91 per kW in the winter months and $13.67 per kW during all other months. The Non-Coincidental Demand Charge will be increased from the present $4.75 per kW to $5.25 per kW. The Energy Charge will be increased from $0.0499 per kWh ($0.0494 per kWh including the RTA) to $0.0521 per kWh.

Table 25 Comparison of Present and Proposed Interruptible Service (Full Interruptible Option) (70)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$110.00/month	$130.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Non-Coinc. Demand Charge	$4.75/kW	$5.25 /kW
Energy Charge	$0.0499/kWh	$0.0521/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	($0.0005)/kWh	$0.0000/kWh

Interruptible Service - Partial Interruptible Option (71)

Dakota Electric proposes the same retail rates for Schedule 71 as Schedule 70. The difference between these two services is that Schedule 70 consumers agree to fully interrupt their load during specified load control periods. Schedule 71 members, however, agree to reduce their load during control periods but not necessarily to zero. Accordingly, these consumers will have some portion of their load on during the control periods.

Table 26 Comparison of Present and Proposed Interruptible Service (Partial Interruptible Option) (71)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$110.00/month	$130.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$24.85/kW/month	$26.14 /kW/month
Winter Months	$18.95/kW/month	$19.91 /kW/month
Other Months	$13.00/kW/month	$13.67 /kW/month
Non-Coinc. Demand Charge	$4.75/kW	$5.25 /kW
Excess Demand	$5.00/kW	$5.00/kW
Energy Charge	$0.0499/kWh	$0.0521/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0060/kWh	$0.0000/kWh

Cycled Air Conditioning Service (80)

Dakota Electric's pricing for the four options under cycled air conditioning service reflect the savings we experience in wholesale capacity charges by members agreeing to control their air conditioners during peak periods. An analysis of wholesale power cost savings associated with cycled air conditioning is presented in Exhibit__(DEA-13). Based on this analysis, we propose no changes in the credit provided to the members participating in cycled air conditioning. The proposed rates for these options are presented below:

Table 27
Comparison of Present and Proposed
Controlled Air Conditioning Service (80)

Description	Present Rate	Proposed Rate
Option 1		
Option 2	($0.0320)/kWh	($0.0320)/kWh
Option 3	($13.00)/month	($13.00)/month
Option 4	($6.50)/ton/month	($6.50)/ton/month

Q. Have you prepared comparisons of the Present and Proposed Rates?

A. Yes, I have. Exhibit__ (DEA-6) provides several different comparisons of the present versus proposed rates as follows:

- Comparison of Present and Proposed Rates
- Comparison of Revenue under Present and Proposed Rates
- Comparison of Bills under Present and Proposed Rates for Selected Classes

Q. Is Dakota Electric proposing changes to other charges in addition to the rate schedules identified above?

A. Yes. Dakota Electric is proposing changes to its special fees and charges per occurrence as follows:

Description	Current Charge	Proposed Charge
Meter Test at Customer's Request		
Single phase	$85.00	$95.00
Three phase	$100.00	$110.00
Bad Check	$15.00	$11.50
Reconnection Charge (after disconnect, same customer)		
Self-Contained Meter:		
Normal working hours	$50.00	$55.00
After hours	$130.00	$145.00
Transformer-Rated Meter:		
Normal working hours	$175.00	$185.00
After hours	$315.00	$340.00
Service Charge (outside normal working hours when problem is not with DEA equipment)	$280.00	$340.00
Load Management Service Charge:		
Normal working hours	$70.00	$80.00
After hours	$140.00	$160.00
Pulse Meter	$500.00	$750.00
~~Temporary Service:~~		
~~Non-winter months~~	~~$205.00~~	NA
~~Winter months~~	~~$340.00~~	NA
Transfer/Connection	$ 17.50	$17.50

These changes are supported by the cost analysis presented in Exhibit__(DEA-10). The Temporary Service special fees listed are being deleted since there is already language in our Rate Book (Section VI, Sheet 8) that describes the provision of Temporary Service. This sheet states that "When installing temporary service to a member, Dakota Electric Association will require that the member bear the cost of the installation and removal of service in excess of any salvage realized." While this language has been in place, Dakota Electric has been charging according to the rates identified for Special Fees or Charges. It is more appropriate for these installations to pay the actual costs for each specific installation.

Q. Are there any other proposed changes?

A. As I mentioned earlier, Dakota Electric is also proposing to update its line extension charges. The present line extension policy provides a base footage allowance of 75 feet, with a $500.00 charge imposed on all individual residential line extensions plus $8.30 per foot for extensions in excess of 75 feet. Based on the analysis in Exhibit__(DEA-11), Dakota Electric proposes to change individual residential line extension charges to a base fee of $1,000.00 plus $11.00 per foot for each foot of the extension (no free footage allowance). We are also proposing language that would refund the amount paid for individual residential line extensions that exceed actual costs for the extension. This proposal for individual residential line extension charges 1) better reflects costs recovered through base rates, 2) helps ensure that new members are paying a more reasonable share of line extension costs, 3) limits payments to no more than actual costs, while 4) reducing the cost burden on existing ratepayers.

Dakota Electric also proposes to update the line extension factors applicable for extensions to members receiving service under Schedule 41, Schedule 46, and Schedules 70/71. These factors are based on the analysis shown in Exhibit__(DEA-11). We also propose to add a factor and line in the calculation description for extensions to multi-tenant residential complexes. This proposed credit per residential unit for multi-tenant master-metered residential buildings is consistent with the residential credit used in the analysis for individual residential line extensions.

Q. Have you prepared revised tariff pages reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit__(DEA-17) includes Dakota Electric's present rate schedules. This exhibit is followed by Exhibit__(DEA-18) that includes marked-up versions of present rate schedules showing all proposed additions and deletions. (The software used for this purpose specifically identifies text that has been deleted. Text proposed for addition is shown as underlined.) Finally, Exhibit__(DEA-19) presents a "clean" version of proposed rate schedules.

VIII. SUMMARY & CONCLUSION

Q. Please summarize your testimony and requests for Commission action.

A. Dakota Electric requests that the Commission:

1. Authorize an overall revenue increase of $8,727,396 or about 4.35 percent.
2. Approve the pro forma Test Year Revenue Requirements contained in Exhibit__(DEA-1).
3. Approve a Rate of Return on Rate Base of 5.73 percent as calculated in Exhibit__(DEA-2).
4. Approve the Cooperative's Cost of Service study as contained in Exhibit__(DEA-3), including the use of the minimum size method (with demand adjustment) in this and future general rate proceedings for the Cooperative.
5. Approve the charges for retail rate schedules as described in this testimony and contained in Exhibit__(DEA-6) and proposed tariff pages included in Exhibit__(DEA-18) and Exhibit__(DEA-19).
6. Approve the RTA base components contained in Exhibit__(DEA-12) and as reflected in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).
7. Approve the proposed Special Fees and Charges shown in Exhibit__(DEA-10) and as reflected in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).
8. Approve the proposed changes for individual residential line extensions as described in this testimony and analyzed in Exhibit__(DEA-11).
9. Approve the proposed modifications/clarifications to tariff pages in Section VI of the Cooperative's rate book as reflected in in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).

Q. Does this conclude your prefiled Direct Testimony?

A. Yes, it does.

Schedule 1
Professional and Educational Background
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-19-478

PROFESSIONAL EXPERIENCE

Dakota Electric Association – Farmington, Minnesota (2008 – Present)

Vice President of Regulatory Services

Responsible for regulatory matters including developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; evaluating power supply issues through participation in meetings at Great River Energy; and monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Power System Engineering – Blaine, Minnesota (1998 – 2008)

Vice President of Rates and Financial Planning

Senior Rate and Financial Analyst

Manager of PSE's Blaine, Minnesota office. Responsibilities include preparation of rate and cost of service analyses for electric cooperative and municipal clients; economic evaluation of mergers, acquisitions and special programs; key account analysis; development of large power contracts and special rates; development of restructuring plans and various elements of such plans; and development of financial forecast and economic feasibility studies.

Dakota Electric Association – Farmington, Minnesota (1992 – 1998)

Director of Regulatory & Legislative Affairs

Coordinated and/or prepared all necessary information pertaining to rate filings, cost of service studies, new rate proposals and miscellaneous tariff filings. Monitored state and federal electric utility and environmental legislation to determine the potential effect on Dakota Electric's operations as a distribution cooperative. Participated in statewide rulemaking proceedings initiated by state agencies that affect electric utility operations. Prepared and conducted conservation, rate and industry-related presentations for consumer and other public meetings.

Dakota Energy Alternatives, Inc. – Farmington, Minnesota (1993 – 1998)

President/CEO – Unregulated Business Activities

Vice President of Business Operations

Supervised staff of professional engineers and support staff who sold and installed standby generation for commercial and industrial customers. Established relationships/partnerships with organizations to expand the standby generation business. Worked with officers to evaluate new business ventures.

Minnesota Department of Public Service – St. Paul, Minnesota (1986 – 1992)

Rate Analyst

Filed testimony in utility rate cases regarding conservation, marketing, cost of service and rate design. Reviewed service area disputes between utilities and complaints from customers and recommended corrective actions. Presented testimony to establish compensation for municipal service territory acquisitions. Reviewed miscellaneous utility filings and prepared recommendations for Public Utilities Commission action. Also participated in Public Utilities Commission task forces to revise Minnesota Rules.

Minnesota Department of Energy & Economic Development, Energy Division
St. Paul, Minnesota (1983 – 1986)

Research Analyst

Responsible for filing testimony in utility rate cases regarding conservation planning and the calculation of cost-effective utility programs. Reviewed utility conservation programs and prepared comments for the Public Utilities Commission.

EDUCATION

University of Minnesota – Minneapolis, Minnesota
Master of Business Administration

St. Olaf College – Northfield, Minnesota
Bachelor of Arts Degree in Economics

Schedule 2
Regulatory Proceedings
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-19-478

Minnesota

Docket Number	Utility	Type of Proceeding
G-009/GR-84-128	Montana-Dakota Utilities	Rate Case
G-007/GR-84-669	Inter-City Gas	Rate Case
G-002/GR-85-108	Northern States Power	Rate Case
G,E-999/R-86-322	Cold Weather Rules	Rulemaking
E-001/GR-86-384	Interstate Power	Rate Case
E-221,148/SA-87-661	City of Buffalo & Wright-Hennepin Cooperative	Service Territory
E-002/GR-87-670	Northern States Power	Rate Case
E-132, 299/SA-88-270	City of Rochester & Peoples Cooperative	Service Territory
E-132,299/SA-88-996	City of Rochester & Peoples Cooperative	Service Territory
E-002/GR-89-865	Northern States Power	Rate Case
E-309,124/SA-89-778	City of Shakopee & Minnesota Valley Coop	Service Territory
G-010/GR-90-678	Midwest Gas	Rate Case
E-002/GR-91-001	Northern States Power	Rate Case
E-002/CN-91-019	Northern States Power	Certificate of Need
E-111/GR-91-074	Dakota Electric Association	Rate Case
E-111/GR-03-261	Dakota Electric Association	Rate Case
E-111/GR-09-175	Dakota Electric Association	Rate Case
E-111/GR-14-482	Dakota Electric Association	Rate Case

Kansas

Docket Number	Utility	Type of Proceeding
01 PNRE 058-RTS	Pioneer Electric Cooperative	Rate Case

Iowa

Docket Number	Utility	Type of Proceeding
RPU-02-1	Linn County REC	Rate Case

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to File, Establish, and make Effective
Revised Rates for the Sale of Electricity

Docket No. E-111/GR-19-478

Volume 1: Transmittal Documents
Interim Petition
Testimony and Exhibits

September 19, 2019

Daniel P. Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

SUBJECT: In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota Docket No. E-111/GR-19-478

Dear Mr. Wolf:

Dakota Electric Association respectfully submits this Application for Authority to Increase Electric Rates (Application) pursuant to Minnesota Statutes 216B.16, Subd. 1. The Application includes changes in present rates and modifications to Dakota Electric Association's special fees and charges.

The name, address, and telephone number of the Cooperative and attorney are as follows:

Representing Attorney:
Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402-4629
(612) 604-6511

Utility Filing for Rate Change:
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
(651) 463-6327

Since our last general rate case was filed in 2014, Dakota Electric has experienced steadily increasing costs in providing electric distribution service. Dakota Electric's 2019 budget anticipates a net operating margin of about $2,250,000 making an increase in rates necessary and unavoidable. Based on our Historical 2018 Test Year operating results (adjusted for known and measurable changes), this filing documents the need for an annual revenue increase of about $8,700,000 or about 4.3 percent.

If the Commission elects to suspend the proposed rate increase under Minnesota Statute 216B.16, Subd. 2, we request that, pursuant to Minnesota Statute 216B.16, Subd. 3, an interim rate increase of approximately $6,000,000 or about 3.0 percent be effective beginning with consumption occurring on and after November 18, 2019, subject to refund (Agreement to Refund attached) should the Commission ultimately approve a lower final revenue level.

We request implementation of the proposed rates within 10 months of the date of Application and request that a Commission Order is received at the beginning of August 2020. However, we understand that multiple general rate proceedings will be filed with the Commission this year. Accordingly, Dakota Electric is willing to provide a limited waiver of the 10-month statutory timeframe, extending the disposition of this case, if such an extension is necessary.

Dakota Electric's Application consists of the following:

Volume 1	Transmittal Documents
	Interim Rate Petition
	Testimony and Exhibits (including proposed rates)
Volume 2	Workpapers (supporting documentation)

To facilitate the review and confirmation of required filing information, attached is a document that identifies Dakota Electric's general rate case compliance requirements with an indication of where each compliance document is located in our submission. These compliance requirements include provisions in Minnesota Rules, Minnesota Statutes, Commission Policy Statements, and the final orders from our last two general rate cases (Docket No. E-111/GR-09-175 and Docket No. E-111/GR-14-482).

Enclosed is a copy of the official notice we propose to provide to customers as a bill insert and to counties and municipalities in our service area through a separate mailing. Upon approval we will begin sending this notice to customers.

In addition to our electronic filing, notice of this general rate case has been sent to those on the Cooperative's general service list and a list of potentially interested persons provided by Commission staff.

Sincerely,

Greg Miller

Gregory C. Miller
President and Chief Executive Officer

Dakota Electric Association
General Service List

Daniel P. Wolf, Exec. Sec.
MN Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Sharon Ferguson
MN Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2198

Eric Swanson
Winthrop & Weinstine
225 South 6th Street, Suite 3500
Minneapolis, MN 55402-4629

Ron L. Spangler, Jr.
Rate Case Manager, Regulatory Services
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538

David R. Moeller
Attorney
Minnesota Power
30 West Superior St.
Duluth, MN 55802

John Lindell
Attorney General's Office - RUD
1400 Bremer Tower
445 Minnesota Street.
St. Paul, MN 55101

Pam Marshall
Energy Cents Coalition
823 East 7th Street
St. Paul, MN 55106

Corey Hintz
Dakota Electric Association
4300-220th Street West
Farmington, MN 55024

Doug Larson
Dakota Electric Association
4300-220th Street West
Farmington, MN 55024

Dakota Electric Association
List of Potentially Interested Persons
General Rate Case
Docket No. E-111/GR-19-478

Jody Johnson
Executive Assistant
Prairie Island Indian Community
jody.johnson@piic.org

Shannon Geshick
Grants and Legislative Director
Minnesota Indian Affairs Council (MIAC)
shannon.geshick@state.mn.us

Heather Westra
Prairie Island Indian Community
heather.westra@piic.org

Certificate of Service

I, Cherry Jordan, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket No. E-111/GR-19-478

Dated this 19th day of September 2019

/s/ Cherry Jordan

____

Cherry Jordan

September 19, 2019

"AGREEMENT TO REFUND"

I, Gregory C. Miller, President and Chief Executive Officer, acting on behalf of Dakota Electric Association, do hereby agree that the Association will refund any portion of the increase in interim rates, determined by the Minnesota Public Utilities Commission to be unreasonable, together with interest thereon.

Gregory C. Miller, President and
Chief Executive Officer
DAKOTA ELECTRIC ASSOCIATION
Farmington, Minnesota 55024

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matt Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of the Application of DAKOTA ELECTRIC ASSOCIATION for Authority to Increase Rates for Electric Service in Minnesota	Docket No. E-111/GR-19-478 September 19, 2019

SUMMARY OF RATE INCREASE PETITION

On September 19, 2019, Dakota Electric Association submitted an Application for Authority to Increase Electric Rates (Application) pursuant to Minnesota Statutes 216B.16, Subd. 1. The Application includes changes in present rates and modifications to Dakota Electric Association's special fees and charges.

Since our last general rate case was filed in 2014, Dakota Electric has experienced steadily increasing costs in providing electric distribution service. Dakota Electric's 2019 budget anticipates a negative net operating margin of about $2,250,000, making an increase in rates necessary and unavoidable. Based on our Historical 2018 Test Year operating results (adjusted for known and measurable changes), this filing documents the need for an annual revenue increase of about $8,700,000 or about 4.3 percent.

If the Commission elects to suspend the proposed rate increase under Minnesota Statute 216B.16, Subd. 2, we request that, pursuant to Minnesota Statute 216B.16, Subd. 3, an interim rate increase of approximately $6,000,000 or about 3.0 percent be effective beginning with consumption occurring on and after November 18, 2019, subject to refund (Agreement to Refund attached) should the Commission ultimately approve a lower final revenue level.

We request implementation of the proposed rates within 10 months of the date of Application and request that a Commission Order is received at the beginning of August 2020. However, we understand that multiple general rate proceedings will be filed with the Commission this year. Accordingly, Dakota Electric is willing to provide a limited waiver of the 10-month statutory timeframe, extending the disposition of this case, if such an extension is necessary.

Dakota Electric Association
General Rate Case Compliance Requirements
Docket No. E-111/GR-19-478

MN Rule	Description	Compliance
Minn. R. 7825.3200(A)	General rate changes shall include items prescribed in Minn. R. 7825.3300 to 7825.4400	See Minn. R. 7825.3300 to 7825.4400 below
Minn. R. 7825.3300	Methods and Procedures for Refunding	Volume 1, "Agreement to Refund"
Minn. R. 7825.3500	Proposal for Change in Rates A. Name, address, etc. B. Date of filing and date of modified rates C. Description and purpose of request D. Effect in gross revenue $ and % E. Signature and title of utility officer	Volume 1, Cover letter
Minn. R. 7825.3600	Modified Rate Schedules and Tariffs	Volume 1, Exhibits 17-19
Minn. R. 7825.3700	Expert Opinions and Supporting Exhibits	Volume 1, Testimony and Exhibits 1-19
Minn. R. 7825.3800	Scope and Supplemental Information	See Minn. R. 7825.3900 to 7825.4400 below
Minn. R. 7825.3900	Jurisdictional Financial Summary Schedule A. The proposed rate base, operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the test year. B. The actual unadjusted rate base, unadjusted operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year. C. The projected unadjusted rate base, unadjusted operating income, overall rate of return, and calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.	Volume 1, Exhibit 2

MN Rule	**Description**	**Compliance**
Minn. R. 7825.4000	Rate Base Schedules A. Summary schedule by major rate base component B. Comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component C. Rate Base Adjustments D. Rate Base Assumptions and Approach E. Rate Base Jurisdictional Allocation Factors (for multijurisdictional utilities)	Volume 1, Exhibit 2
Minn. R. 7825.4100	Operating Income Schedules A. Jurisdictional Operating Income Statements B. Total Utility and Jurisdictional Operating Income Statements C. Utility Income Tax Computations (investor-owned utilities) D. Operating Income Adjustments E. Operating Income Assumptions and Approach F. Operating Income Jurisdictional Allocation Factors (for multijurisdictional utilities)	Volume 1, Exhibit 1 and Exhibit 5
Minn. R. 7825.4200	Rate of Return Cost of Capital Schedules A. Rate of Return Summary Schedules B. Supporting Schedules C. Average Short-Term Securities	Volume 1, Exhibit 2
Minn. R. 7825.4300	Rate Structure and Design Information A. Summary Comparison Test Year Operating Revenue B. Detailed Comparison Test Year Operating Revenue C. Cost of Service Study	A. Volume 1, Exhibit 6 B. Volume 1, Exhibit 6 C. Volume 1, Exhibit 3

MN Rule	Description	Compliance
Minn. R. 7825.4400	Other Supplemental Information A. Annual Report B. Gross Revenue Conversion Factor (Investor-Owned) C. Form 7 (cooperatives) D. Form 7A (cooperatives) E. Form 325 Financial Forecast (cooperatives)	A. Volume 2, WP 2 B. NA C. Volume 2, WP 1 D. Volume 2, WP 1 E. Volume 2, WP 5
Minn. R. 7814.2400, subp. 4	New Base Electric Fuel Cost	Volume 1, Exhibit 12
Minn. R. 7829.2400	Filing requiring determination of gross revenue.	
	Brief summary of the filing, sufficient to apprise potentially interested parties of its nature and general content.	Volume 1, Summary of Filing
	A utility filing a general rate change request shall serve copies of the filing on the Department and Residential Utilities Division of the Office of the Attorney General. The utility shall serve the filing or the summary described in subpart 1 on the persons on the applicable general service list and persons who were parties to its last general rate case or incentive plan proceeding.	Volume 1, Cover Letter

MN Statute	Description	Compliance
Minn. Stat. § 216B.16, subd. 3	Interim Rates	Volume 1, Notice and Petition for Interim Rates, and Interim Rate Schedules
Minn. Stat. § 216B.241 Minn. Stat. § 216B.16, subd. 1	Energy Conservation Improvement Plan	Volume 2, WP 9
Minn. Stat.§ 216B.16, subd.17; Travel, Entertainment and Related Employee Expenses	Schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: (1) travel and lodging expenses; (2) food and beverage expenses; (3) recreational and entertainment expenses; (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (6) dues and expenses for memberships in organizations or clubs; (7) gift expenses; (8) expenses related to owned, leased, or chartered aircraft; and (9) lobbying expenses.	Volume 2, WP 15

Policy Statement	**Description**	**Compliance**
Advertising	Statement that recovery is requested only for permitted advertisements. Description of advertisements for which recovery is requested. Sample advertisements for which recovery is requested.	Volume 2, WP 18
Charitable Contributions	Evidence as to whether the recipients of the contributions: serve the utility's Minnesota service area; are nondiscriminatory in selecting recipients; and do not promote political or special interest groups. Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual. Itemized schedule showing amount, recipient and time of donations. Only 50% of qualified contributions shall be allowed as operating expenses.	Volume 2, WP 19
Organizational Dues	Schedule showing each organization being paid, the number of employees belonging to each organization and the dollar amount of dues being paid to each organization. Testimony explaining the primary purpose of each organization.	Volume 2, WP 20
Research Expenses	Description of each research activity for which an expense is claimed, with all expenses for each activity itemized and supported.	Not Applicable
Cash Working Capital	Lead/lag study with: 1) lead time divided into service to meter reading; meter reading to billing; and billing to collection; and 2) lag expenses divided in categories such as fuel, purchased power, labor. Other issues may include average or minimum cash	Volume 2, WP 6

	balances required, depreciation, dividends and interest on debt.	
Interim Rates	Name, address and telephone number of utility and attorneys. Date of filing and date proposed interim rates are requested to become effective. Description and need for interim rates. Description and corresponding dollar amount change included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues. Certification by officer of the utility. Signature and title of the utility officer authorizing the proposed interim rates. Methods and procedures for refunding. Supporting schedules and work papers. Modified tariffs. Notices.	Volume 1, Notice and Petition for Interim Rates, and Interim Rate Schedules and Volume 1, Transmittal Documents

MPUC Order E-111/GR-09-175	Description	Compliance
Sales Forecast	Dakota Electric shall, in future rate cases, be consistent in its use and source of weather data in determining its sales forecast.	Volume 2, WP 13
Long-Term Interest Expense	Dakota Electric shall, in its next rate case, demonstrate that its long-term interest expense is prudently incurred. Such demonstration shall include data of rates offered by other lenders.	Volume 2, WP 17
Minimum-Size Method	Dakota Electric shall, in its next rate case, either use the minimum-size method to classify distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method.	Volume 2, WP 21
Line Extensions	Regarding line extensions, if Dakota Electric determines that there has been any increase in the number of its overhead extensions, it shall include that information in its next rate case.	Volume 1, DRL Testimony

MPUC Order E-111/GR-14-482	Description	Compliance
Purchased-Power	Dakota Electric Association shall include in the initial filing of its next rate case work papers for both the purchased-power revenue and purchased-power expense amounts included in the pro forma test-year financial schedule.	Volume 2, WP 24
COS Demand Adjustment	Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.	Volume 2, WP 21 and Volume 1, Exhibit 3

Misc. Dockets	**Description**	**Compliance**
E-999/CI-06-159	In an August 10, 2007 Order, the Commission stated its intention to examine individual utility smart metering practices in the context of rate cases.	Volume 2, WP 25
E-111/M-16-774	The Association will track the wholesale power cost credits associated with each Member Specific Discount and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.	Volume 1, Exhibit 12
E-111/M-16-923	The Association will track the wholesale power costs associated with All Large Load High Load Factor credits and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Minnesota Public Utilities Commission. This will ensure that the credits Dakota Electric receives from its wholesale power supplier are not double-counted.	Volume 1, Exhibit 12
E-111/M-17-180	The Association will track the wholesale power costs associated with all contract rates and exclude them from both the calculation of the base cost of power in future rate cases and the calculation of the Power Cost Adjustment Charges in the Resource and Tax Adjustment filings to the Commission.	Volume 1, Exhibit 12

Proposed changes for base electricity rates

Dakota Electric Association has asked the Minnesota Public Utilities Commission (MPUC) for permission to increase electric utility rates and service charges. The proposed increase in total cooperative annual revenues will be about $8.7 million or 4.3% overall.

Interim rates

State law allows us to collect higher rates on an interim basis while our rate filing is reviewed. If the MPUC approves our request for $6.0 million or a 3.0% interim increase, the additional charge will apply to electricity use beginning in November, for which members will begin receiving bills in December. This interim increase appears on your bill as "Interim Rate Adjustment." For Residential and Small General Service members, the interim adjustment applies to the monthly fixed charge, energy charge and resource and tax adjustment*. For General Service members the interim adjustment also applies to the demand charge.

The interim increase will remain in effect until the MPUC determines final rates. The MPUC is expected to make its decision in 2020. If the approved overall total increase is lower than interim rates, we will refund members the difference with interest. If the overall total increase is higher, we will not charge members the difference.

What is increasing Dakota Electric's costs?

Since Dakota Electric's last request for a rate increase in 2014, costs for equipment, labor and materials have continued to increase. These factors, combined with minimal growth in electric sales in the last five years, contributed to the need for this filing.

How is Dakota Electric controlling costs?

- Using technology and process improvements to increase efficiency.
- Employees do things every day to reduce expenses. They may not produce large savings on their own but when added together, help lower expenses.
- Offering a variety of programs to help members conserve energy and save money.

Impact on monthly bills

While the effect of the proposed increase on your bill will vary depending upon member classification and amount of energy use, the average monthly bill for a residential member will increase by $4.22 from $94.96 per month to $99.18 per month. The charts below provide more detail on the impact of proposed increases.

Proposed Change in Monthly Electricity Costs

Member classification	Average monthly kWh use	Current monthly bill	Interim monthly bill	Proposed final monthly bill
Residential	700	$94.96	$97.81	$99.18
Small General Service	1,000	$132.90	$136.89	$142.00
General Service	16,000	$1,637	$1,686	$1,654

Energy (per kWh) and Demand (per kW) Rates (including RTA)

Member classification	Current	Proposed
Residential		
Energy: Summer (June - Aug)	13.33¢	13.79¢
Energy: Other (Sept - May)	11.93¢	12.39¢
Small General Service		
Energy: Summer (June - Aug)	12.94¢	13.75¢
Energy: Other	11.54¢	12.35¢
General Service		
Energy: First 200 kWh per kW	8.01¢	7.76¢
Energy: Next 200 kWh per kW	7.01¢	6.76¢
Energy: Over 400 kWh per kW	6.01¢	5.76¢
Demand: Summer (June - Aug)	$12.26	$13.70
Demand: Other (Sept - May)	$9.16	$10.60

Monthly Fixed Charges

Member classification	Current	Proposed
Residential	$9.00	$10.00
Small General Service	$14.00	$15.00
General Service	$34.00	$34.00

*The resource and tax adjustment (RTA) is a periodic rate adjustment for changes in wholesale power costs, property and real estate taxes and conservation spending.

Review process

The Minnesota Public Utilities Commission will hold public hearings and accept written comments about our rate request. The public will be able to comment on our rate request at the public hearings. You may add oral comments, written comments, or both into the record. Dakota Electric will provide details about the hearings in local newspapers, in a bill insert and at www.dakotaelectric.com.

More information

Details about proposed rates are available on Dakota Electric's Web site at www.dakotaelectric.com. A complete copy of our filing is also available for review at our Farmington office between 8 a.m. and 4:30 p.m. Monday through Friday. Our office is located at 4300 220th Street West, Farmington, MN.

You may also examine our current and proposed rate schedules and our request for new rates by contacting the Department of Commerce at:

Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101
Phone: 651-296-9314

Web site: https://www.edockets.state.mn.us/EFiling/search.jsp. Web address is case sensitive. Select 19 in the year field, enter 478 in the number field, click on search and the list of documents will appear on the next page.

Dakota Electric will also keep members informed of rate filing developments in our monthly *Circuits* newsletter and at www.dakotaelectric.com. As always, if you have questions or comments for Dakota Electric, contact us at 651-463-6212 or rates@dakotaelectric.com.

How to participate

Anyone who wishes to formally intervene in this case should contact:

Minnesota Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620
Phone: 651-361-7900

Citizens with hearing or speech disabilities may call through their preferred Telecommunication Relay Service.

You do not need to contact the Minnesota Office of Administrative Hearings if you simply want to attend the public hearings, provide oral comments at the public hearings or submit comment letters.

You may submit written comments to:

Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147
Phone: 651-296-0406 or 800-657-3782
E-mail: consumer.puc@state.mn.us

Citizens with hearing or speech disabilities may call through their preferred Telecommunication Relay Service.

Be sure to reference MPUC Docket No. E-111/GR-19-478 in all correspondence or requests.

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
651-463-6212
www.dakotaelectric.com

Dakota Electric seeks increase in electric rates

Interim rates effective with usage on and after November__, 2019 until final decision is made.

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

4300 220th Street West, Farmington, MN 55024
651-463-6212 • 800-874-3409
www.dakotaelectric.com

Docket No. E-111/GR-19-478

**Interim Rate Schedules –
Showing Markup**

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability
Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	$14.70 per kW
Other	@	$11.10 per kW
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability
Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$10.10
150 Watt High Pressure Sodium (Closed to new)	$11.99
250 Watt High Pressure Sodium (Closed to new)	$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67
Plus Applicable Taxes	

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability
Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service
The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability
Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service
The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44 - 4
LED SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens) $7.63 per month
Plus Applicable Taxes

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 10.60	$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 11.24	$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.31	$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.71	$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

SCHEDULE 46
GENERAL SERVICE

Availability
Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge
The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service
A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability
Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.0940 per kWh Plus applicable taxes

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Metering
The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor
The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

DAKOTA ELECTRIC ASSOCIATION
4300 220th Street West
Farmington, MN 55024

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability

Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0440 per kWh
Plus Applicable Taxes.		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand

The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes

The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Energy Charge	@	$0.0550 per kWh
Plus Applicable Taxes.		

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
		Plus
Maximum Demand Charge	@	$ 4.75 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability
Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

INTERIM RATE ADJUSTMENT RIDER

Availability

The 3.0% Interim Rate Adjustment applies to:

1. Fixed Charge
2. Energy Charge
3. Demand Charge
4. Resource and Tax Adjustment
5. Minimum Charges
6. Energy Charge Credits
7. Voltage Discounts
8. Lighting Rates per Luminaire
9. Low Wattage Unmetered Service
10. Standby Reservation Fees
11. Controlled Air Conditioning and Water Heating Discounts

The Interim Rate Adjustment does not apply to:

1. Municipal Civil Defense Sirens
2. Special Fees or Charges
3. Communication Fee
4. Competitive Service Rider
5. Franchise Fee Surcharge Rider
6. Optional Renewable Energy Rider
7. Member Energy Exchange Rider
8. Voluntary Energy Reduction Rider
9. Member Specific Discount Rider
10. Large Load High Load Factor Rider
11. Contract Rate Service
12. Advanced Grid Infrastructure Rider
13. Advanced Meter Opt-Out (AMO) Rider
14. Late Payment Charge

This temporary Interim Rate Adjustment Rider will expire when final rates become effective.

Rate

Each rate schedule that the Interim Rate Adjustment applies to contains the following text:

> Interim Rate Adjustment
> A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November __, 2019.

Docket No. E-111/GR-19-478

**Interim Rate Schedules –
Clean**

SCHEDULE 31
RESIDENTIAL AND FARM SERVICE

Availability

Available to individual residential and farm members for all domestic and farm use except irrigation. This includes service to apartment units. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$9.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1308 per kWh
Other	@	$0.1168 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 32
RESIDENTIAL AND FARM DEMAND CONTROL RATE

Availability
Available to residential and farm members with at least 5 kW of qualifying off-peak loads as determined by the Association. This rate is subject to the rules and regulations of the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve (12) months.

Type of Service
Single phase, 60 Hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		$ 0.0760 per kWh
Demand Charge		
Summer (June-Aug)	@	$14.70 per kW
Other	@	$11.10 per kW
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Billing Demand Determination
The demand will be determined based on the peak 15-minute demand reading during control periods for the month the bill was rendered . An estimated demand will be used for new customers until the actual controlled demand is established.

Minimum Monthly Charge
The minimum monthly charge under the above rate shall be the $12.00 Fixed Charge plus a minimum billing demand of 3 kW.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be increased or decreased by $0.0001 per kilowatt-hour for each 0.1 mill or major fraction by which the energy component in the Association's purchased power cost per kilowatt-hour purchased from its power supplier exceeds, or is less than $0.0903 per kilowatt-hour purchased. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE EV-1
PILOT – RESIDENTIAL ELECTRIC VEHICLE SERVICE

Availability

Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck. Service on this tariff is limited to electric vehicles that are SAE J1772 compliant and registered and operable on public highways in the State of Minnesota. Low-speed electric vehicles, including golf carts, are ineligible to take service under this tariff even if licensed to operate on public streets. The consumer may be required to provide the Association with proof of registration of the electric vehicle prior to taking service under this tariff. Service is subject to the established rules and regulations of the Association.

Term

The pilot program will be offered for a minimum of a two year period. At the end of the initial two year pilot period, the Association will determine if this program will be continued, modified, or eliminated. If it is eliminated, the consumers participating in the pilot program will revert back to the appropriate retail rate tariff for their class of service.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Rate

Energy Charges:

Off-Peak:	6.74¢ per kWh
On-Peak:	41.44¢ per kWh
Other:	Schedule 31 energy charges apply

Plus RTA and applicable sales tax

Definition of Periods

Energy Charge time periods are defined as follows:

Off-Peak	9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays
On-Peak	4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays
Other	8:00 am to 4:00 pm Mon. – Fri., excluding Holidays

Holidays shall be: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 36
IRRIGATION SERVICE

Availability

Available to any member for service to irrigation pumps. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Firm Service

Fixed Charge		$30.00 per month
Demand Charge		
Summer (June-Aug)	@	$26.35 per kW
Winter (Dec-Feb)	@	$20.95 per kW
Other	@	$15.50 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interruptible

Fixed Charge		$30.00 per month
Demand Charge	@	$4.55 per kW
Energy Charge	@	$0.0499 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

SCHEDULE 41
SMALL GENERAL SERVICE

Availability
Available to any commercial member for all uses, except irrigation pumps, where the Metered Demand is 15 kW or less. If the Metered Demand exceeds 15 kW for three consecutive months, the member will be transferred to the General Service Rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$14.00 per month
Energy Charge		
Summer (June-Aug)	@	$0.1269 per kWh
Other	@	$0.1129 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand
The Metered Demand in kilowatts shall be the greatest 15-minute demand during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge
The Minimum Monthly Charge under the above rate shall be the Fixed Charge.

Non-metered Option
This option has limited availability. It may be available for: devices that are located at individual points of delivery and are operated with a continuous or predetermined load level that exceeds the threshold determined for Schedule 45. The monthly energy consumption will be determined by the Association based on equipment documentation provided by the member. The maximum monthly energy allowed under this option will be 500 kWh.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 44
SECURITY LIGHTING SERVICE

Availability
Available for year-around illumination for private residential, farm, or commercial lighting on existing Association service poles where service poles and service wires can be connected on the line side of member's meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
The Association shall own, operate, and maintain the security lighting system using the Association's standard security lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
100 Watt High Pressure Sodium (Closed to new)	$10.10
150 Watt High Pressure Sodium (Closed to new)	$11.99
250 Watt High Pressure Sodium (Closed to new)	$15.79
Plus Applicable Taxes	

Optional – For residential or farm installation requiring any extra equipment, or in the event the consumer requests the changeout of an existing light to a different size and/or type, a contribution to construction will be required to cover the extra costs incurred. Commercial installations on existing service poles only.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-1
STREET LIGHTING SERVICE
(MEMBER – OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards where member owns the lighting system complete with standards, luminaries, globes, lamps, and other appurtenances, together will all necessary cables extending between standards and to point of connection to the Association's facilities as designated by the Association.

Type of Service

The street lighting system shall be built and owned by the member. All controls will be provided by the member. The member shall also provide all easements and right-of-way to permit access to feed points. The Association shall operate and provide limited maintenance (periodic cleaning of lens, refractor, and bulb replacement) on street lighting systems.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$10.52
250 Watt Mercury (Closed to new)	$13.46
400 Watt Mercury (Closed to new)	$18.54
100 Watt High Pressure Sodium	$7.56
150 Watt High Pressure Sodium	$9.46
200 Watt High Pressure Sodium	$11.41
250 Watt High Pressure Sodium	$13.25
400 Watt High Pressure Sodium	$17.67

Plus Applicable Taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-2
STREET LIGHTING SERVICE
(DEA – OWNED EQUIPMENT)

Availability

Available for governmental or private year-around illumination of public or private streets, parkways, highways, and other public ways by electric lamps in luminaires supported on existing poles where secondary voltage is available and the facilities for this service are furnished by the Association.

Type of Service

The Association shall own, operate, and maintain the overhead street lighting system using the Association's standard street lighting equipment. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$15.23
250 Watt Mercury (Closed to new)	$18.16
400 Watt Mercury (Closed to new)	$23.25
100 Watt High Pressure Sodium (Closed to new)	$12.27
150 Watt High Pressure Sodium (Closed to new)	$14.16
250 Watt High Pressure Sodium (Closed to new)	$17.95
400 Watt High Pressure Sodium (Closed to new)	$22.38
Plus Applicable Taxes	

The above rates cover only an installation where the pole with secondary voltage is existing at the light location. Contributions to construction costs will be required if additional equipment is needed or if a member requests a change to a different lamp size and/or type when costs exceed $500.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44-3
CUSTOM RESIDENTIAL STREET LIGHTING
(DEA-OWNED – CONTRIBUTION BY MEMBER)

Availability
Available for year-round illumination of public streets, parkways, highways, and other public ways by electric lamps mounted on standards and served through underground circuits, where the facilities for this service are furnished by the Association. Street lighting service under this schedule is limited to residential areas having an underground distribution area.

Type of Service
The Association shall own, operate, and maintain the lighting system using the Association's standard street lighting equipment which includes one lamp per standard. Member shall be required to contribute an amount equal to the installation cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

Designation of Lamp	Monthly Rate Per Luminaire
175 Watt Mercury (Closed to new)	$11.37
50 Watt High Pressure Sodium (Closed to new)	$6.70
100 Watt High Pressure Sodium	$8.41
150 Watt High Pressure Sodium (Closed to new)	$10.30
250 Watt High Pressure Sodium (Closed to new)	$14.09
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment or in the event the member requests the changeout of an existing light to be a different size and/or type, the member will be required to pay all construction fees or extra charges incurred.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 44 - 4
LED SECURITY LIGHTING SERVICE

Availability

Available for year-around illumination for private residential, farm, or commercial lighting by Light Emitting Diode (LED) electric lamps on existing Association service poles where service poles and service wires can be connected on the utility side of the meter. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED security lighting system using the Association's standard LED security lighting equipment. Fixtures on this rate will only be attached to an existing DEA service pole. The energy used by these lights is unmetered.

Monthly Rate

Light Emitting Diode Security Light (LED, > 4,500 lumens)	$7.63 per month
Plus Applicable Taxes	

Optional – For installations requiring any extra equipment (excluding poles), a contribution to construction will be required to cover the extra costs incurred. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

SCHEDULE 44-5
LED STREET LIGHTING
(MEMBER-OWNED)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished and owned by the Member. Service is subject to the established rules and regulations of the Association.

Type of Service

The member shall own, operate, and maintain the LED lighting system.

The preferred service option is metered LED lighting. Such service will be billed to the Member under the rate schedule associated with the meter.

Unmetered service will be allowed if the Association determines it is not practical for the lights to be metered. For such unmetered use:

1. Billing will be according to specified consumption groups. Dakota Electric will determine if a member qualifies for the unmetered rate and which consumption group.
2. The Member will be required to provide Dakota Electric with a notice prior to any change in equipment.
3. No other use is allowed from the fixture. (e.g. Wi-Fi attachments, holiday lights, etc.)
4. The Association will periodically inspect the unmetered fixtures to ensure compliance with requirements.
5. The Member must provide proof of lighting system rating. (i.e. data sheet or model number)

No maintenance will be included in the monthly rate from the Association for any member-owned LED street light. At the request of a Member, Dakota Electric may enter into individual contracts with a Member for the type and frequency of maintenance they may desire from the Association.

Monthly Rate

Metered Service: According to applicable rate schedule

Unmetered Service:

Consumption Group	Monthly Rate per Fixture
A (40 to 80 watts)	$4.81
B (81 to 150 watts)	$6.71
C (151 to 250 watts)	$9.66
D (251 to 350 watts)	$13.05
E (351 to 450 watts)	$16.52

Plus Applicable Taxes

The range of watt ratings for the Unmetered Consumption Groups will be adjusted periodically to reflect the predominant size of lights receiving such Unmetered Service.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

SCHEDULE 44-6
LED STREET LIGHTING
(DEA-OWNED - CONTRIBUTION BY MEMBER)

Availability

Available for year-round illumination of public streets, parkways, highways, and other public ways by Light Emitting Diode (LED) electric lamps served through underground or overhead circuits, where the facilities for this service are furnished by the Association. Conversion of existing lighting to LED lighting may be limited to accommodate workload scheduling. Street lighting service under this schedule is limited to designated LED lighting fixtures offered by the Association in its distribution area. Service is subject to the established rules and regulations of the Association.

Type of Service

The Association shall own, operate, and maintain the LED lighting system using the Association's standard street lighting equipment which includes one fixture per pole. Member shall be required to contribute an amount equal to the initial installation or upgrade cost of the lighting system. The energy used by these lights is unmetered.

Monthly Rate

	Monthly Rate per Fixture	
Designation of Fixture	Standard	Basic
Light Emitting Diode (LED, > 5,200 lumens) Coach Light (Post)	$ 10.60	$6.83
Light Emitting Diode (LED, > 5,200 lumens) Acorn Light (Post)	$ 11.24	$6.30
Light Emitting Diode (LED, > 7,000 lumens) Cobra Light (Mast)	$ 8.31	$6.51
Light Emitting Diode (LED, > 11,500 lumens) Shoebox Light (Mast)	$ 10.71	$7.98
Plus Applicable Taxes		

The Coach and Acorn fixtures will be mounted on a street light post. The Cobra and Shoebox fixtures will be fastened to a mast arm on existing service poles. In the event the member requests the change out of an existing light, the member will be required to pay all construction fees and material costs for the new installation or upgrade as well as payment for the undepreciated cost of the existing light, less any salvage value.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceeds, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 45
LOW WATTAGE UNMETERED SERVICE

Availability
This rate is available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level. Each individual electronic device must not in any way interfere with Association operations and service to adjacent members. This rate is also available to equipment connected to the supply side of the service disconnect such as fire and sprinkler alarms, and emergency lighting systems, if such equipment is used only during times of emergency. This will require verification from a licensed electrical contractor/electrician in the form of an affidavit.

This Low Wattage Unmetered Service is not applicable to electric service for traffic signals, civil defense, or lighting. Association reserves the right to evaluate member requests for this service to determine eligibility.

Type of Service
Either single phase or three phase, depending on feasibility, 60 hertz, at available secondary voltages.

Installation Charges
The member shall pay the total estimated installation charges involved to provide service.

Monthly Rate
$10.00 per month per service location, plus applicable sales tax.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes
The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance

SCHEDULE 46
GENERAL SERVICE

Availability

Available to any commercial member for all uses except irrigation. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$34.00
Demand Charge		
Summer (June-Aug)	@	$12.26 per kW
Other	@	$ 9.16 per kW
Energy Charge		
First 200 kWh per kW	@	$0.0776 per kWh
Next 200 kWh per kW	@	$0.0676 per kWh
Over 400 kWh per kW	@	$0.0576 per kWh
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Metered Demand

The Metered Demand in kilowatts shall be the greatest 15-minute demand (subject to power factor adjustment) during the month for which the bill is rendered. Demand will be read to the nearest 0.01 kilowatt.

Determination of Energy Charge

The energy (kWh) billed in each rate block is determined in relation to the monthly demand (kW). The energy in the first block includes the first 200 kWh multiplied by the monthly metered demand. The second block includes the next 200 kWh multiplied by the monthly metered demand. All energy in excess of 400 kWh multiplied by the monthly metered demand is billed under the third block.

Power Factor Adjustment

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the demand for billing purposes shall be the demand as recorded by the demand meter multiplied by 90 percent and divided by the percent power factor.

Minimum Monthly Charge

The Minimum Monthly Charge under the above rate shall be the Fixed Charge plus $1.00 per kW of the highest billing demand during the preceding 11 months.

Primary Voltage Service

A discount of $0.15/kW of Billing Demand will be applied to the bill when service is taken by the member at the available primary voltage. If primary metering is used, an additional discount of 2.0 percent shall be applied to the bill. The 2.0 percent discount shall be applied after the $0.15/kW discount.

SCHEDULE 49
GEOTHERMAL HEAT PUMP RIDER
(Closed to new consumers.)

Availability

Available to any commercial member for energy used by a geothermal heat pump system. Members requesting service under this rate schedule must be taking service concurrently under Rate Schedule 41 or 46. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Rate

Energy Charge	$0.0940 per kWh Plus applicable taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Metering

The geothermal heat pump system must be separately, parallel metered from all other loads at the premise. Service will not be sub-metered.

Power Factor

The member agrees to maintain as near unity (100 percent) power factor as practicable. The Association reserves the right to measure such power factor at any time. Should such measurements indicate that the average power factor is less than 90 percent, the energy for billing purposes shall be adjusted accordingly.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kWh, or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour for this service annually exceeds, or is less than, $0.0775 per kWh sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted as necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 51
CONTROLLED ENERGY STORAGE

Availability
Available to members taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available for approximately eight hours per day, normally 11:00 p.m. to 7:00 a.m., or as established by the Association.

Monthly Rate

Energy Charge	@	$0.0440 per kWh
Plus Applicable Taxes.		

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0200 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the storage load is coincident with the member's other loads. When feasible, new controlled energy storage loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 52
CONTROLLED INTERRUPTIBLE SERVICE

Availability
Available to member taking service concurrently under rate schedules 31, 41 and 46. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service
Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate
Energy Charge @ $0.0550 per kWh
Plus Applicable Taxes.

Alternate Monthly Rate for Controlled Water Heaters
Where separate metering of controlled water heaters is not possible or for members on Rate 53, a direct credit of $1.50 per 100 kWh used up to a maximum of $6.00 per month will be applied against the monthly bill.

Interim Rate Adjustment
A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Resource and Tax Adjustment (RTA)
The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The energy cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected weighted average power cost per kilowatt-hour for this service exceeds, or is less than $0.0305 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

Demand
The metered demand of loads on this rate will be subtracted from the metered demand for members receiving service under Schedule 41 and 46 when the interruptible load is coincident with the member's other loads. When feasible, new controlled interruptible services loads should be on a separate service from Schedule 41 and 46 load.

Taxes
The rates set fourth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Terms of Payment
The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

SCHEDULE 53
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charge		
Summer – (June-Aug) Peak Period	@	$0.1880 per kWh
Other – Peak Period	@	$0.1740 per kWh
Off-Peak Period	@	$0.0940 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 54
GENERAL SERVICE
OPTIONAL TIME-OF-DAY RATE

Availability

Available to any member for general service electrical loads. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		\$36.00 per month
Peak Period Demand Charge		
Summer (June-Aug)	@	\$24.85 per kW
Winter (Dec-Feb)	@	\$18.95 per kW
Other	@	\$13.00 per kW
		Plus
Maximum Demand Charge	@	\$ 4.75 per kW
Energy Charge	@	\$0.0499 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Period	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 4:00 p.m., plus all day on holidays and weekends

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Determination of Billing Demand

1. Peak Period - The Peak Period Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) between 4 p.m. and 11 p.m. during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.
2. Maximum Demand - The Maximum Billing Demand shall be the greatest 15 minute demand (subject to power factor adjustment) during the month for which the bill is rendered, as indicated or recorded by a demand meter. Demand will be read to the nearest 0.01 kilowatt.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge plus \$1.00 per kW of the highest Maximum Billing Demand during the preceding 11 months.

SCHEDULE 56
RESIDENTIAL AND FARM SERVICE
TIME-OF-DAY RATE

Availability

Available to residential and farm members for all domestic and farm use, except irrigation pumps. Members participating in this service are not eligible for either Schedule 51 or Schedule 52. Members will be required to remain on this rate for a minimum of 12 months. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, when economically feasible, 60 hertz, at available secondary voltages.

Monthly Rate

Fixed Charge		$12.00 per month
Energy Charges		
Peak Periods:		
Summer – (June-Aug)	@	$0.2710 per kWh
Winter – (Dec-Feb)	@	$0.2210 per kWh
Spring/Fall	@	$0.1750 per kWh
Intermediate Period	@	$0.0970 per kWh
Off-Peak Period	@	$0.0760 per kWh
Plus Applicable Taxes		

Definition of Periods

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

Holidays include New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Minimum Monthly Charge

The minimum monthly charge under the above rate shall be the Fixed Charge.

Resource and Tax Adjustment (RTA)

The Energy Charge shall be adjusted for incremental changes in purchased power costs, incremental changes in Dakota Electric's conservation tracker account balance, and incremental changes in real and personal property taxes above or below the appropriate base costs. The conservation tracker account factor shall be calculated as described in the Resource Adjustment Rider (Sheet 51). The real and personal property tax factor shall be calculated as described in the Property Tax Adjustment Rider (Sheet 53). The purchased power cost factor shall be adjusted by $0.0001 per kilowatt-hour or major fraction thereof, of which the Association's total projected power cost per kilowatt-hour annually exceed, or is less than $0.0903 per kilowatt-hour sold. The year used for the annualized RTA will be January 1 through December 31. The projection shall be reviewed after six months (July) and adjusted if necessary. The RTA shall be filed with the Public Utilities Commission each year before implementation.

SCHEDULE 60
RIDER FOR STANDBY SERVICE
CONTINUED

Definitions

Contracted Standby Demand is the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply and will not exceed the capacity of the member's distributed generation system.

Firm Service refers to a utility's most reliable, constant electric service. A utility would interrupt the supply of electricity to a firm service customer only as a last resort.

Non-Firm Service, also called interruptible service, refers to electric service that a utility provides only to the extent that it has capacity not being used to meet the needs of firm-service members at the moment.

All other definitions shall be as described in Cooperative's *Distributed Generation Interconnection Requirements* and *Interconnection Process for Distributed Generation Systems.*

Charges for Service

The following Reservation Fees, Communication Fee, Usage Fees, and Wheeling Fees will be assessed as applicable in addition to all charges for service being taken under Cooperative's base rate schedule:

Reservation Fees

Charges as specified below for the reservation of either Firm or Non-Firm generation, transmission and distribution service per Month per kW will each be applied to the member's Contracted Standby Demand as specified in member's Electric Service Agreement with Cooperative:

	Firm Service ($ per kW)	Non-Firm Service ($ per kW)
Generation	*	**
Transmission	*	**
Distribution - Secondary Service	$3.51	$3.51
Distribution - Primary Service	$3.28	$3.28
Distribution - Substation Service	$0.90	$0.90

* Firm Standby Service generation and transmission Reservation Fees will be billed under the rates, terms and conditions of the Cooperative's wholesale power supplier (Great River Energy), which is available on GRE's Web site; greatriverenergy.com and DEA's Web site; dakotaelectric.com.

**Generation and transmission Reservation Fees are not applied for Non-Firm Service. However, members will be responsible for all costs associated with wholesale power supply during any times of usage.

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Communication Fee

A monthly Communication Fee will be applied to cover the cost of transmitting data through the use of digital cellular equipment. The monthly Communication Fee is applied to each required meter with cellular data capabilities.

Communication Fee $8.70 per meter

Usage Fees

Demand Charge

If the member registers electrical usage from Cooperative during a billing month then such usage will result in demand charges which may vary between members contracting for Firm Standby Service or Non-Firm Standby Service.

SCHEDULE 70
INTERRUPTIBLE SERVICE
(FULL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the full interruptible control option, members agree to interrupt their entire electrical energy usage. Members may attain this full interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load must go to zero.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June-Aug)	@	$24.85 per kW
Winter (Dec-Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Failure to Control Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the full interruptible control option shall be defined as the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) when the load is directed to be controlled during the wholesale billing peak.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

Failure to Control

The Failure to Control Charge will be applied to the highest kilowatt demand during any one monthly control period when the member does not fully interrupt demand. The Failure to Control Charge is applied to the highest demand recorded during any one of the monthly control periods. The control period shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system. Failure to control or being unavailable for control for more than one calendar month may require the member to be removed from Schedule 70 for the remainder of the year.

Scheduled Maintenance

Members are encouraged to schedule required periodic maintenance during the spring and fall months and coordinate such maintenance with the Association.

SCHEDULE 71
INTERRUPTIBLE SERVICE
(PARTIAL INTERRUPTIBLE OPTION)

Availability

Available to any member with a minimum controllable demand of 50 kW. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of 12 months. Members participating in this service are not eligible for concurrent service under any other rate schedule. Service is subject to the established rules and regulations of the Association.

Under the partial interruptible control option, members agree to reduce a portion of their electrical energy usage. Members may attain this partial interruption through curtailment or with the use of on-site generation back-up. During the interruption, the member's load goes to a Predetermined Demand Level (PDL). If a partial interruptible member fails to control demand to the PDL, then the PDL will be adjusted to the demand occurring during such control period.

Type of Service

Single phase or three phase, 60 hertz, at available primary or secondary voltages.

Monthly Rate

Fixed Charge		$110.00 per month
Communication Fee (meters w/ digital cellular)		$8.70 per month
Coincidental Demand		
Summer (June – Aug)	@	$24.85 per kW
Winter (Dec – Feb)	@	$18.95 per kW
Other	@	$13.00 per kW
Non-Coincidental Demand	@	$ 4.75 per kW
Energy Charge	@	$ 0.0499 per kWh
Excess Demand Charge	@	$ 5.00 per kW
Plus Applicable Taxes		

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Control Period

The control period shall be shall be defined as the period of time during which the Association is controlling these loads with the intent of minimizing demand on the Association's system.

Coincidental Demand

The monthly Coincidental Demand under the partial interruptible control option shall be defined as:

- During a month with no control period, the monthly Coincidental Demand under the partial interruptible control option will be the lesser of the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak) or the Predetermined Demand Level.
  During a month with a control period, the monthly Coincidental Demand under the partial interruptible control option will be the member's actual hourly demand (subject to power factor adjustment) that is coincident with the wholesale power supplier (i.e. average of the four fifteen minute demand readings for the hour ending of the wholesale billing peak).

The partial interruptible PDL will be adjusted to any higher actual demand of the member occurring during a curtailable event for the remainder of the calendar year. In the case of members using on-site generation, the PDL may be adjusted to reflect the rated capacity of such generation that was not operational during the control period. Only one such adjustment per year will be allowed.

Non-Coincidental Demand

The Non-Coincidental Demand shall be the maximum kilowatt demand (subject to power factor adjustment) established by the member for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a demand meter.

SCHEDULE 80
CYCLED AIR CONDITIONING SERVICE

Availability

Available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association. Service is subject to the established rules and regulations of the Association.

Type of Service

Single phase or three phase, 60 hertz, at available secondary voltages. Service under this schedule will be available at all times except when interrupted by the Association during times of peak system demand or system emergencies.

Monthly Rate

Option No. 1 - Available to members who also take service under Schedules 51 and 52 where an existing meter and control unit may be utilized for the controlled air conditioning load.

Energy Charge per applicable Schedule 51 or 52

Option No. 2 - Available to members where a new meter and control unit must be installed to control the air conditioning load.

Energy Charge Credit @ $0.0320 per kWh

Option No. 3 - Available to members where a control unit must be installed to control the air conditioning load.

A credit will be applied to the first $13.00 of the member's net energy consumption charges in the months of June, July, and August. In no case will the credit exceed the sum of the monthly Energy Charge and Resource and Tax Adjustment.

Option No. 4 - Available to non-residential members where a new meter and control unit must be installed but where it is not feasible or designed to meter the air conditioning load separately. The maximum capacity of any individual air conditioning compressor is 7.5 tons. A $6.50 per ton per month credit will be applied to member's bill in the months of June, July, and August. The aggregate monthly credit per account will not exceed 1/3 of the net charges for energy and demand in each month.

Plus Applicable Taxes

Interim Rate Adjustment

A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November 18, 2019.

Taxes

The rates set forth are based on taxes as of January 1, 2014. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder shall be added to the above rate as appropriate.

Terms of Payment

The above charges are net. Balances over $10.00 not received by the Association by the next scheduled billing date will have an interest charge of 1.5 percent or $1.00, whichever is greater, added to the balance.

INTERIM RATE ADJUSTMENT RIDER

Availability

The 3.0% Interim Rate Adjustment applies to:

1. Fixed Charge
2. Energy Charge
3. Demand Charge
4. Resource and Tax Adjustment
5. Minimum Charges
6. Energy Charge Credits
7. Voltage Discounts
8. Lighting Rates per Luminaire
9. Low Wattage Unmetered Service
10. Standby Reservation Fees
11. Controlled Air Conditioning and Water Heating Discounts

The Interim Rate Adjustment does not apply to:

1. Municipal Civil Defense Sirens
2. Special Fees or Charges
3. Communication Fee
4. Competitive Service Rider
5. Franchise Fee Surcharge Rider
6. Optional Renewable Energy Rider
7. Member Energy Exchange Rider
8. Voluntary Energy Reduction Rider
9. Member Specific Discount Rider
10. Large Load High Load Factor Rider
11. Contract Rate Service
12. Advanced Grid Infrastructure Rider
13. Advanced Meter Opt-Out (AMO) Rider
14. Late Payment Charge

This temporary Interim Rate Adjustment Rider will expire when final rates become effective.

Rate

Each rate schedule that the Interim Rate Adjustment applies to contains the following text:

> Interim Rate Adjustment
> A 3.0% Interim Rate Adjustment will be applied as specified in the Interim Rate Adjustment Rider effective for service rendered on and after November __, 2019.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matt Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates
for Electric Service in Minnesota

Docket No. E-111/GR-19-478
September 19, 2019

NOTICE AND PETITION FOR INTERIM RATES

A. Introduction

Dakota Electric Association ("Dakota Electric" or "Cooperative") submits to the Minnesota Public Utilities Commission ("MPUC" or the "Commission") this Petition for Interim Rates (the "Petition") for retail electric rates to members, pursuant to Minn. Stat. § 216B.16 subd. 3; the Commission's Statement of Policy on Interim Rates dated April 14, 1982; and relevant Commission rules.

B. Information Provided Pursuant to the Commission Statement of Policy on Interim Rates and Relevant Commission Rules

1. Name, address, and telephone number of utility and attorney.
(Policy Statement, Item 1, page 2)

Utility Filing for Rate Change:
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
(651) 463-6212

Representing Attorney:
Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402-4629
(612) 604-6511

2. Date of filing and date proposed interim rates are requested to become effective. (Policy Statement, Item 2, page 2)

This Petition is filed September 19, 2019. The Petition is submitted as part of the Cooperative's Application for a General Electric Rate Increase (the "Application"), which is also being filed on September 19, 2019. Pursuant to Minn. Stat. § 216B.16,subd.3, Dakota Electric requests, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. § 216B.16, subd. 2, that the proposed interim rates be made effective with consumption occurring on and after November 18, 2019. The interim rates will be subject to refund, pending final Commission determination on the general electric rate increase.

3. Description and need for interim rates.
(Policy Statement, Item 3, page 2)

Dakota Electric proposes an interim rate increase of three percent (3.0%), which will apply to retail rates as specified in the proposed Interim Rate Adjustment Rider. Interim rates are necessary because the Cooperative has experienced increasing costs of service as reflected in the Cooperative's general rate application. The proposed 3.0% interim rate increase is anticipated to be sufficient to maintain positive annual margins beginning in 2020. We calculated the proposed interim rates consistent with Commission requirements and precedent. Specifically, when determining the interim rate request, the overall rate of return ("ROR") requested for interim rates for Dakota Electric uses the present average cost of long-term debt and the return on equity previously authorized by the Commission in Dakota Electric's last rate case (Docket No. E-111/GR-14-482). The proportion of each component and the factor to adjust the weighted cost of capital to establish return on rate base is also consistent with the numbers approved in the final order from our last general rate case. Overall, this adjustment results in an interim revenue deficiency of about $8,460,000 or about 4.2 percent, which is greater than the requested interim increase of 3.0% and slightly lower than the overall increase of about 4.3% requested in this proceeding.

Minn. Stat. § 216B.16, subd. 3(b) provides that unless "the commission finds that exigent circumstances exist, the interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include (1) a rate of return on common equity for the utility equal to that authorized by the commission in the utility's most recent rate case proceeding."

In calculating interim rates, Dakota Electric proposes an amount that is less than the amount authorized under the interim rates statute, but sufficient to meet financial metrics during the rate case proceeding while providing a transitional step to final rates. As the Commission found in the Cooperative's last two rate case proceedings, charging the Association's members more than the Association believes its operations require for interim rates would contravene the public interest. The Commission has agreed that Dakota Electric's proposed approach to interim revenue increases in past rate cases is reasonable and in the public interest. Therefore, Dakota Electric requests that the Commission find that exigent circumstances exist and not require Dakota Electric to apply the capital structure and cost of capital set by statute when determining the interim rate increase in this rate case. The Association's request avoids collecting more revenue than necessary during this proceeding and provides a transitional increase in rates should the Commission ultimately order the rates requested.

<u>4. Description and corresponding dollar amount of changes included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available.
(Policy Statement, Item 4, page 2)</u>

A comparison of the Interim Petition and Application revenue deficiencies is attached to this Petition. The difference in the two calculations relates to the overall rate of return. The Application calculates a ROR of 5.73%, while the Interim Petition uses a 5.59% percent ROR calculated as follows:

Component	Proportion	Cost Rate	Weighted Cost
Long-Term Debt	41.81%	3.77%	1.58%
Return on Equity	58.19%	4.28%	2.49%
Weighted Cost of Capital	100%		4.07%
Return on Rate Base		1.373	5.59%

In any event, Dakota Electric is requesting an interim revenue increase below the revenue deficiency identified in both the Application and Interim Petition calculations.

<u>5. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues.
(Policy Statement, Item 5, page 2).</u>

The test year for Dakota Electric's general rate increase filing is the historical 2018 calendar year adjusted for known and measurable changes. Dakota Electric requests an interim rate adjustment that will increase Dakota Electric's base rate (distribution) revenues by about $6,000,000 or 3.0 percent above the test year gross revenues. This interim rate adjustment will be uniformly billed as a 3.0 percent increase on the subtotal of members' bills. As noted, this interim increase is below the possible interim increase of about $8,460,000 calculated according to Commission requirements and precedent for interim adjustments. The proposed Interim Tariff clause describes the interim rate increase and is consistent with the application of interim rates approved by the Commission in Dakota Electric's last two general rate cases (Docket No. E-111/GR-09-175 and Docket No. E-111/GR-14-482). We have further refined that explanation by developing an Interim Rate Surcharge Rider, which lists those charges to which the interim rate increase applies and a list of those rates to which the interim rate increase does not apply. This Rider is identical to the Rider approved by the Commission in our last two general rate cases. Dakota Electric proposes that a uniform percentage be applied to all of the base rate elements listed in the Interim Rate Surcharge Rider, with such interim revenue being used to support our distribution operations. That is, Dakota Electric proposes to continue all present charges, including the RTA, and apply the 3.0

percent interim adjustment to the subtotal of such charges. All such interim revenue will be applied to the Cooperative's provision of electric distribution service.

6. Certification by Chief Executive Officer.
(Policy Statement, Item 6, page 2)

This Petition contains a certificate signed by Greg Miller, President and CEO, Dakota Electric Association, affirming that this interim rate Petition complies with Minnesota Statutes and is attached to this petition.

7. Methods and procedures for refunding.

Pursuant to Minn. Stat. § 216B.16, subd. 3, Dakota Electric's Agreement and Undertaking to make appropriate refunds if required is contained in the Application.

8. Signature and title of the utility officer authorizing the proposed interim rates. (Policy Statement, Item 7, page 2)

The Petition is signed on behalf of Dakota Electric by Greg Miller, President and CEO, Dakota Electric Association.

9. Supporting schedules and workpapers.
(Policy Statement, Items 1-4, page 3)

The supporting documentation described in the Commission's Policy Statement is included with this Petition and Application. These schedules include the rate base amounts; income statement amounts; revenue deficiencies; rates of return required for interim rates as compared to the same information for Dakota Electric's general rate increase Application.

10. Interim rate schedules, Revenue rate comparisons.
(Minn. R. 7825.3600)

A summary of the revenue increases under present and proposed interim rates for all customer classes is included in this Petition. The rate schedules containing proposed interim rates are also included with this Petition. Consistent with Minn. Stat. § 216B.16, subd. 3, no change has been made in the existing rate design. A uniform percentage equal to the proposed interim rate increase needed to recover the interim revenue deficiency from base rates has been applied to all billing components as described in the Interim Rate Adjustment Rider.

11. Customer Notice.
(Minn. R. 7829.2400, subpt. 3; Minn. Stat. § 216B.16, subd. 1)

Pursuant to Minn. R. 7829.2400, subpt. 3, and Minn. Stat. § 216B.16, subd. 3, Dakota Electric proposes to send a notice to its members and to the counties and municipalities in our service area. In addition, Dakota Electric will publish a display advertisement in the newspapers of general circulation in Dakota County. Pursuant to Minn. Stat. § 216B.16, subd. 1, the proposed notice to consumers, counties and municipalities is included in this filing and can be found in the transmittal information in the Application.

12. Interim Bills.

The Commission's Policy Statement on Interim Rates suggests that changes in interim rates be shown on customer bills as a separate line item "if practical." The interim rate amount will be shown as a separate line item stated as "Interim Rate Adjustment," and will reflect the total amount of the interim charge applied to the bill.

C. Conclusion

Dakota Electric respectfully requests, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. 216B.16, subd. 2, that the proposed interim rates be made effective with consumption occurring on and after November 18, 2019, subject to refund, pending final Commission action on the Cooperative's general electric rate increase Application.

Dated: September 19, 2019
Respectfully submitted,

Greg Miller
President & CEO
Dakota Electric Association