Rochester Public Utilities

2009
Electric System
Engineering & Operations
Report

ROCHESTER PUBLIC UTILITIES
ENGINEERING & OPERATIONS REPORT
(Electric System)
2009

Cover Photo Description:

<u>Photo on the Left</u>
RPU crews work at replacing a failed underground switch located in a manhole near the Peace Plaza downtown.

<u>Photo on the Right</u>
RPU crews working along 19^{th} St NW on the new transmission line extension that will feed the new Westside Substation located at the intersection of 19^{th} St NW and 60^{th} Av. The new transmission line is scheduled to be in service in the fall of 2010.

Report prepared by Mike Engle and Jill Boldt

ROCHESTER PUBLIC UTILITIES
ENGINEERING & OPERATIONS REPORT – 2009

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A. Technical Services Summary

1. Revenue Services Maintained/Installed

LGS & Industrial Meters (1 yr. cycle)	
Total number of Meters	27
Total number of meters maintained on schedule	27
Meters maintained (goal)	27
Meters maintained (actual)	27

MGS Services (4 yr. cycle)	
Total number of services	436
Total number of meters maintained on schedule	436
Meters maintained (goal)	105
Meters maintained (actual)	105

Residential & SGS Services (16 yr. cycle)	
Total number of meters	47,285
Meters maintained (goal)	3,000
Meters maintained (actual)	*

2. Substation/Miscellaneous

Transformer, breaker, and switch oil tests	196
Switches, breakers, & associated relays maintained (13.8kV)	29
Switches, breakers, & associated relays maintained (161kV)	10
Substation transformers maintained	7
Radio and TV interference problems	12
Distribution transformers maintained	126
Voltage/Power Quality Problems/Projects	36

Notes:

Maintenance cycles for substation equipment are:

- 13.8kV breakers	5 yr.
- 161kV breakers	5 yr.
- transformers	5 yr.
- protective relays in substations	5 yr.
- protective relays in power plants	5 yr.

3. AMR

	2009 Installed	Total in Service
Water AMR Units	3,060	35,604
Electric AMR Units	*	*

B. Gopher State One-Call Activity

Total Requests

Water	8,065
Electric	9,809
Gross Total	10,641

* Not available at this time. Reports have not been written to retrieve this information from the CCS System.

C. Division Performance Indices

The following statistics have been developed as indicators of Division performance. Some are considered reflective of Division performance as a whole (DIV), while others are more related to a particular Section's performance (EN, P, SO, or TD). There are very few single-year indicators that we have total control over: the weather can intervene in many of them. However, multi-year averages should be indicative of Division efforts, and are also useful in comparing RPU to regional and national performance.

Target indices are being established in relation to national averages, to RPU's internal goals, and/or to simply improving present performance.

Formulas used are the same as those used by APPA. Statistics involving number of customers or employees use year-end quantities.

Some indices remain unavailable due to difficulties in establishing a reliable method of gathering the information. Each year, we will evaluate the cost-versus-benefit value of each of the indices, and determine whether to continue to collect the information.

Rochester Public Utilities
2009 Performance Indicators
Operations Division

Item	Name	Target Value	2009	Previous 5 Year Avg	2008	2007	2006	2005	2004	Comments
100	Avg Customer-Minutes Without Power (SAIDI)	< 53	56.9	44.00	25.44	53.23	72.47	34.88	33.99	
101	Avg Outage Length in Minutes (CAIDI)	< 40	80.24	74.53	75.59	99.3	99.3	46.15	52.29	
102	Avg Installed Cost/Residential Subd Lot	---	*	1,161.79	*	1,520.95	1,566.00	1,363.00	1,359.00	Very little residential development in 2009
103	Avg Installed Cost/Ft-1PH URD in Conduit	---	7.12	7.09	7.60	7.51	7.24	6.75	6.35	UMS Calculations, OH changes, no equipment
104	Avg Installed Cost/3PH Circuit Ft 336MCM	---	18.79	17.43	19.61	18.34	17.14	15.89	16.17	UMS Calculations, OH changes, no equipment
200	600V Distr Transformer KVA/Peak Sys KW	1.5 - 1.75	1.905	1.74	1.828	1.75	1.64	1.71	1.78	480V and Below

Maintenance & Construction Section

Item	Name	Target Value	2009	Previous 5 Year Avg	2008	2007	2006	2005	2004	Comments
205	Paid (Non-Billed) Overtime Hours/Tech Services	---	403.9	714.80	1032	554	665	759	564.00	
500	Avg Number of Customers Served/T&D Employee	> 1,200	1644	1628	1663	1591	1688	1628	1569	
501	Distribution Circuit Miles/T&D Employee		25.04	24.60	25.16	24.02	25.36	24.22	24.24	
502	Avg Tree Trimming Cost/Mile - Transmission		759.54	220.41	502.54	376.63	72.60	150.29	0.00	
503	Avg Tree Trimming Cost/Mile - OH Distribution		1,496.30	1,284.38	1,095.52	1,427.26	1,506.00	1103.7	1,289.42	
505	Paid (Non-Billed) Overtime Hours/T & D		2209.55	2,000.37	1896	2384.95	2060	1759.88	1,901.00	
506	Total Number of Accidents + Near-Misses/T & D	0	14	15.00	16	15	18	16	10.00	

Rochester Public Utilities
2009 Performance Indicators
Operations Division

Power Production Section

Item	Name	Target Value	2009	Previous 5 Year Avg	2008	2007	2006	2005	2004	Comments
300	Forced Outage Factor - Hydro	0	0	0.00	0	0	0	0	0.00	
301	Forced Outage Factor - SLP #1	0	0.52	52.52	0	161	96	0.96	4.66	
302	Forced Outage Factor - SLP #2	0	2.18	48.11	0	144	96	0	0.57	
303	Forced Outage Factor - SLP #3	0	1.23	47.53	13.58	181.5	0	25.77	16.82	
304	Forced Outage Factor - SLP #4	0	2.51	77.89	11.34	177.7	181.3	11.55	7.54	
305	Forced Outage Factor - Combustion Turbine 1	0	0.39	35.29	36.9	64.24	67.09	0	8.22	
305B	Forced Outage Factor - Combustion Turbine 2		28.53	1.78	1.66	2.45	0.39	0	4.41	
306	Availability Factor - Hydro	95	100	100.00	100	100	100	100	100.00	
307	Availability Factor - SLP #1	95	84.96	91.21	95.37	87.94	98.08	85.62	89.04	
308	Availability Factor - SLP #2	95	91.47	90.41	95.37	88.78	98.08	90.13	79.71	
309	Availability Factor - SLP #3	95	74.11	81.49	81.35	90.52	100	66.29	69.27	
310	Availability Factor - SLP #4	95	81.18	76.74	67.29	85.89	70.78	74.51	85.22	
311	Availability Factor - Combustion Turbine 1	95	95.52	53.64	48.03	35.76	32.91	87.67	63.84	
311B	Availability Factor - Combustion Turbine 2	95	58.86	92.46	91.46	94.64	99.61	88.39	88.2	
312	Capacity Factor - Hydro	---	39.42	55.33	52.95	63.46	54.62	49.59	56.05	
313	Capacity Factor - SLP #1	---	0.89	16.16	4.46	11	14.6	27.7	23.03	
314	Capacity Factor - SLP #2	---	24.98	26.94	29.13	18.95	22.6	38.19	25.81	
315	Capacity Factor - SLP #3	---	1.19	34.64	24.27	43.88	37.1	32.41	35.53	
316	Capacity Factor - SLP #4	---	7.55	36.12	24.69	41.49	28.72	35.81	49.88	
317	Capacity Factor - Combustion Turbine 1	---	0	0.04	0	0	0	0	0.19	
317B	Capacity Factor - Combustion Turbine 2		2.61	6.57	5.89	14.79	9.72	1.41	1.03	
318	O&M Cost Per Net MWH - Hydro		4.50	8.21	6.17	5.64	8.18	5.37	15.68	
319	O&M Cost Per Net MWH - SLP #1		379.93	39.06	56.77	29.34	43.02	43.83	22.34	
320	O&M Cost Per Net MWH - SLP #2		229.82	23.78	32.74	27.05	11.78	13.56	33.79	
321	O&M Cost Per Net MWH - SLP #3		199.62	14.49	20.22	20	5.3	12.59	14.33	
322	O&M Cost Per Net MWH - SLP #4		10.13	7.24	10.66	7.49	4.19	8	5.84	
323	O&M Cost Per Net MWH - Combustion Turbine 1		-13.64	3.18	36.82	53.35	-441.42	22.39	344.76	
323B	O&M Cost Per Net MWH - Combustion Turbine 2		-0.92	1.18	2.11	3.77				
324	URGE Test Rating (MW) - Hydro	> 1,500	1,650	1,515	1,500	1,500	1,500	1,500	1,575	
325	URGE Test Rating (MW) - SLP #1	> 9,500	9310	9,431	9565	9468	9650	9386	9,087	
326	URGE Test Rating (MW) - SLP #2	> 13,500	13,814	14,197	14,330	14,024	14,167	13,366	15,098	
327	URGE Test Rating (MW) - SLP #3	> 24,000	24,750	24,300	23,500	24,250	24,500	24,250	25,000	
328	URGE Test Rating (MW) - SLP #4	> 59,000	56,767	58,793	56,467	58,732	59,223	59,498	60,043	
329	URGE Test Rating (Seas Avg, MW)- C.Turbine 1	> 35,000	28,810	29,870	30,176	31,416	31,420	26,430	29,910	Avg of Winter/Summer ratings
330	URGE Test Rating (Seas Avg, MW)-C. Turbine 2	> 49,500	49,608	49,039	49,465	49,152	49,535	47,160	49,885	
331	Total URGE Rating of All Units	> 192,000	104,641	181,223	185003	188542	190270	151700	190,598.00	
332	Labor Hours/MWH Gross Generation		0.14	0.30	0.45	0.27	0.37	0.23	0.17	Plant labor only
333	Total Overtime Hours		304	1,754.60	1911.5	2128.5	1508	1556	1,669	
334	Incidence Rate of Injury Days Lost		7.61	6.04	8.71	3.45	5.25	5.15	7.64	
335	Avg Training-Safety Hours Per Employee		21.6	96.48	40.9	31.2	360.6	18.9	30.8	
336	Avg Training-Safety Cost Per Employee		990.31	1,278.04	2211.59	1522.86	1067.51	624.08	964.18	
337	Avg Sick Leave Hours Per Employee	< 44	35.6	44.64	46	46.2	45.8	43.9	41.30	
338	Avg Number of Employees (Including Director)		56	51	53	51	50	52	51	

II. TRANSMISSION SYSTEM SUMMARY

A. Circuit Miles of 161kV Transmission 40.51

B. Transmission Substation Transformers

Substation	Transformer	Voltage	MVA
Cascade Creek	GSU 2	13.8/161kV	37.5/50/62.5/70
Silver Lake	GSU 4	13.8/161kV	37.5/50/62.5/70

Total Transmission Substation Capacity 75/100/125/140

C. Distribution Substation Transformers 161/13.8kV
Rates listed are 55°C rise self-cooled/first stage of cooling/second stage of cooling/65°C rise with both stages of cooling.

Substation	Transformer	MVA
Cascade Creek	T1	20/27/33/37
	T2	15/20/25/28
Bamber Valley	T1	15/20/25/28
Zumbro River	T1	15/20/25/28
	T2	15/20/25/28
IBM	T1	20/27/33/37
	T2	20/27/33/37
Northern Hills	T1	15/20/25/28
	T2	15/20/25/28
Silver Lake	T4	20/27/33/37
	T3	20/27/33/37
Mayo	T1	20/27/33/37
	T2	20/27/33/37
Willow Creek	T1	15/20/25/28
	T2	15/20/25/28

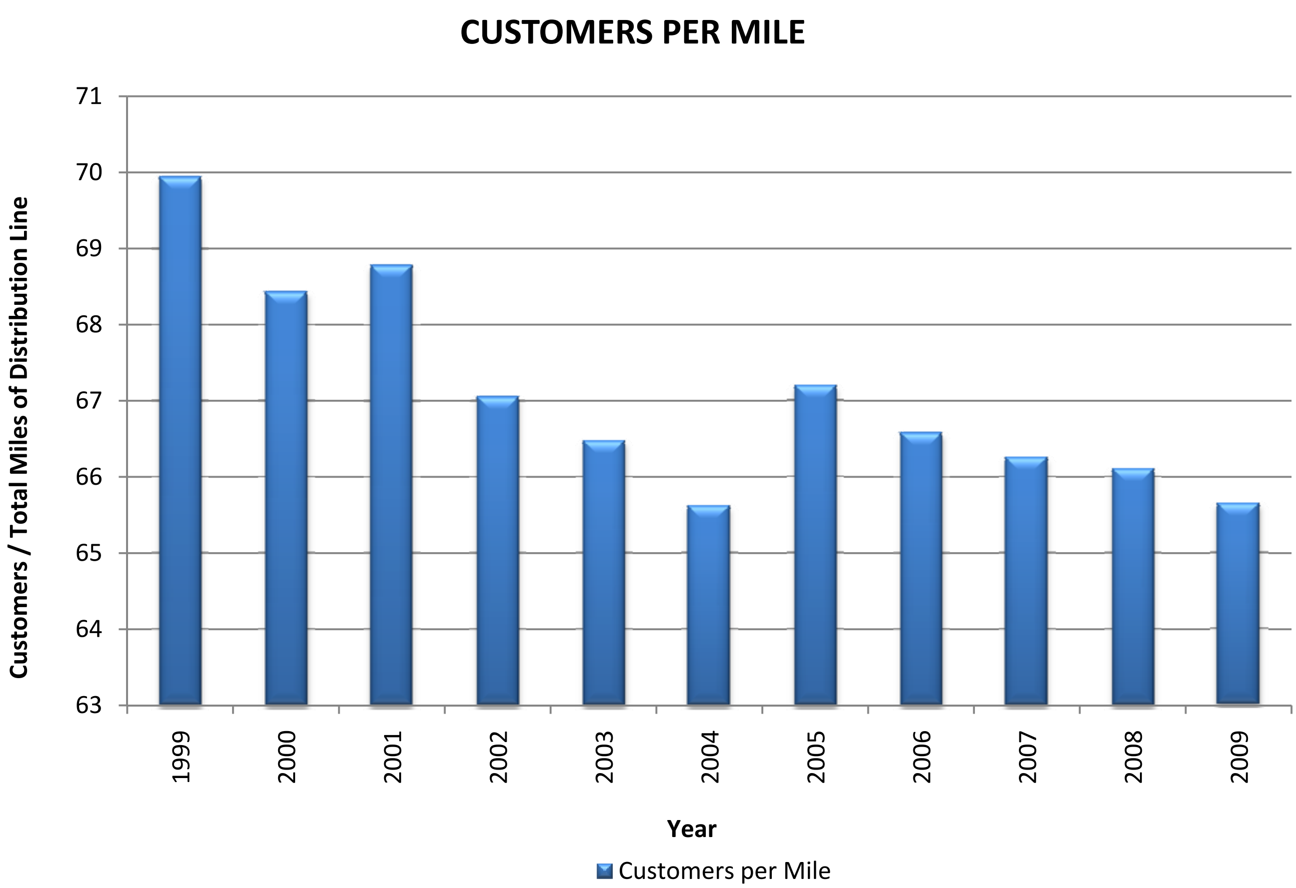
Total Distribution Substation Capacity 260/349/431/483

III. DISTRIBUTION SYSTEM SUMMARY

A. Circuit Miles

3Ø Circuit Miles	
1. Overhead (2.58 miles added in 2009)	160.53
2. Underground (3.22 miles added in 2009)	126.43
Total 3Ø Miles	286.96
2Ø Circuit Miles	
1. Overhead (0 removed in 2009)	1.96
2. Underground (0 miles removed)	0
Total 2Ø Miles	1.96
1Ø Circuit Miles	
1. Overhead (2.11 miles removed in 2009)	106.22
2. Underground (1.16 miles added in 2009)	331.01
Total 1Ø Miles	437.23
Total Miles of Distribution System Line	726.15

Figure 1



B. Utility Poles (totals as of 12/31/2009)

1.	Total Number of Wood Distribution Poles in System (30'-55')	11950
	Net Pole Usage (Poles Issued-Returned to Stock)	106
2.	Total Number of Transmission Poles in System	940

Concrete Height	Concrete Count	Wood Height	Wood Count	Steel Height	Steel Count
85	11	30 *	1	65	1
90	9	35 *	9	70	1
95	10	40	9	75	7
100	4	45	6	76	1
105	3	50	89	80	6
110	3	55	37	85	15
115	1	60	36	86	1
120	0	65	66	88	1
125	0	70	53	89	2
Total	41	75	45	90	27
		80	110	91	1
		85	145	93	2
		90	120	94	2
		95	46	95	7
		100	15	97	2
		105	5	98	1
		110	7	99	1
		115	1	100	6
		120	0	102	1
		125	1	103	1
		Total	801	105	10
				111	1
				115	0
				120	0
				125	1
				Total	98

3. Rented Poles in the System

RPU Rents from Qwest	722
RPU Rents from PCPA	29
Total Number of Poles RPU Rents	751
Qwest Rents from RPU	2,586
Charter Communications Rents from RPU	6,856
McLeod Rents from RPU	496
PCPA Rents from RPU	200
Norlight Rents from RPU	10
Onvoy	0
Enventis Telecom	5
Total Number of Poles Rented from RPU	10,153

C. Street and Rental Lights

Total Number of Streetlights and Rental Lights on System

A. Streetlights

	2008	2009	Net Change
175W MV	464	450	-14
250W MV	5	5	0
400W MV	46	46	0
175 MH	35	35	0
250 MH	45	45	0
100W HPS	6508	6588	80
250W HPS	1378	1397	19
400W HPS	227	220	-7
	8708	8786	

B. Rental Lights

70W MV	1	1	0
70W HPS	33	33	0
100W HPS	382	389	7
175W MV	113	115	2
250W HPS	612	610	-2
400W MV	15	10	-5
400W HPS	19	18	-1
150 HPS Roadway	149	148	-1
	1324	1324	

*** MH = Decorative lights installed at Shoppes on Maine**

IV. SERVICE TERRITORY

A. Geographic Area

	Square Miles
1974 assigned area:	30.88
Acquired through 12-31-09:	26.58
Current assigned territory:*	57.46

* People's continues to serve customers in portions of the acquired areas.

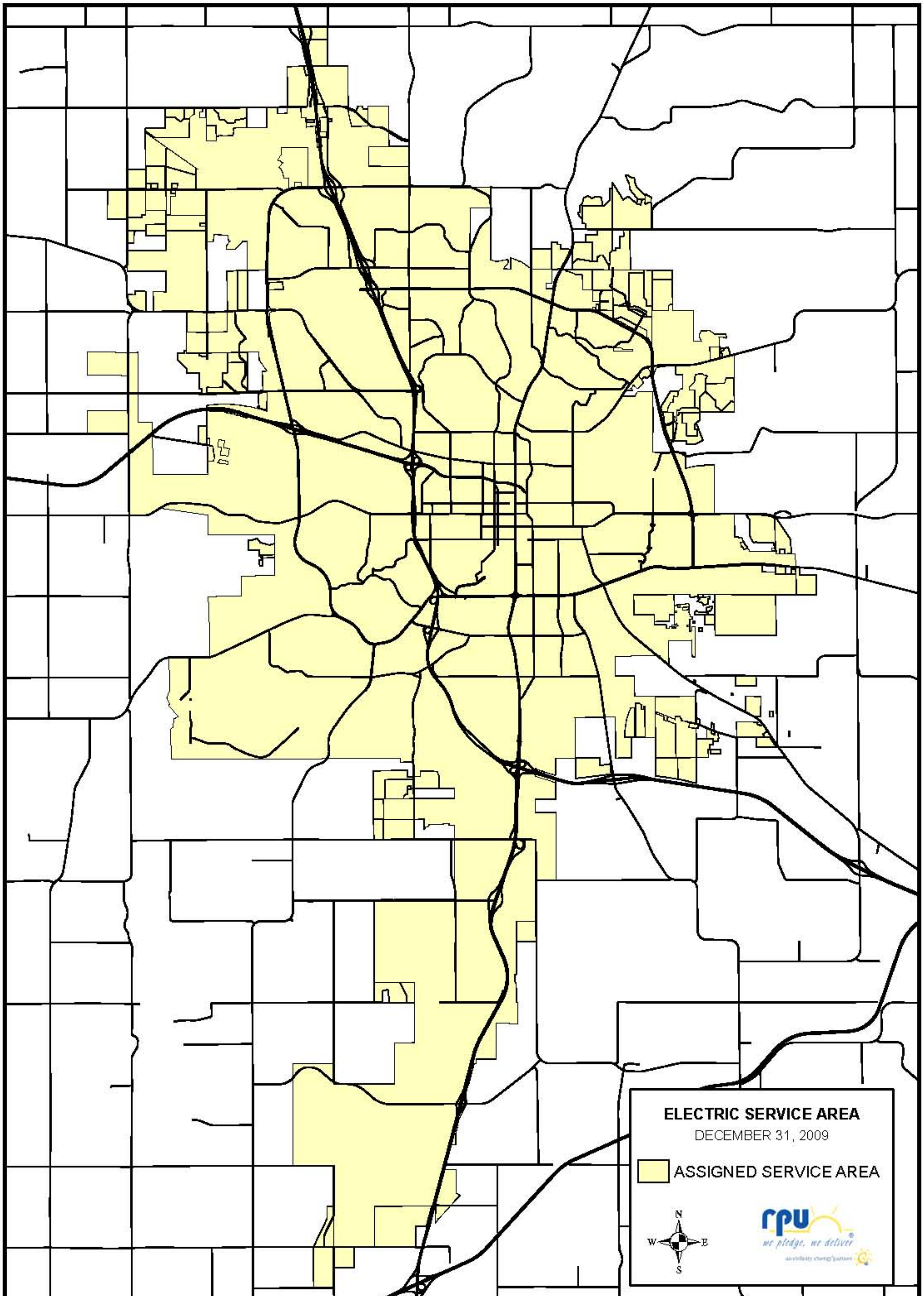
B. Chronology of Events

- RPU and Peoples met several times to begin the process of transferring existing PCS customers to RPU's system based on the 2008 agreement. The decision was made to allow PCS to continue to serve customers in the Marvale area until the remaining water quality areas were annexed on January 1, 2010.
- No agreement has been reached on the compensation period for annexations over 80 acres.
- Approximately 1200 existing PCS customers are to be transferred as part of the 2008 agreement. As of 12/31/2009 30 existing customers have been transferred.
- Peoples CEO continued to lobby City administration and the Council to rescind the 1990 ordinance stipulating RPU will provide service to all annexed areas.
- No additional statewide meetings with the Coops took place.

C. Compensation paid in 2009

Millrate payments: $509,482

D. Escrow Account (was closed due to the 2008 agreement)


ELECTRIC SERVICE AREA
DECEMBER 31, 2009
ASSIGNED SERVICE AREA
N
W
E
S
rpu
we pledge, we deliver

V. DEMAND MANAGEMENT SUMMARY

A. Project Status

- Installed 23 residential and 0 commercial load management terminals.
- Maintained load management hardware.
- Responded to 18 load management callouts.

B. Residential Load Management Terminal Installations

	2007	2008	2009
A/C	127	49	23
Dual	1	0	0
W/H	3	2	0
Total	131	51	23

C. Commercial Load Management Terminal Installations

	2006	2007	2009
A/C	0	0	0
W/H	0	0	0
Total	0	0	0

VI. TRANSFORMER SUMMARY

A. New Distribution Purchases

	2008		2009	
	Number	Number	Number	KVA
Aerial	24	24	69	1,655
Padmount	80	80	77	9,525
	104	14,652.5	140	11,180

B. Miscellaneous

	2007	2008	2009
Ratio of Connected kVA vs. System Peak Demand	1.746	1.828	1.905

Figure 2

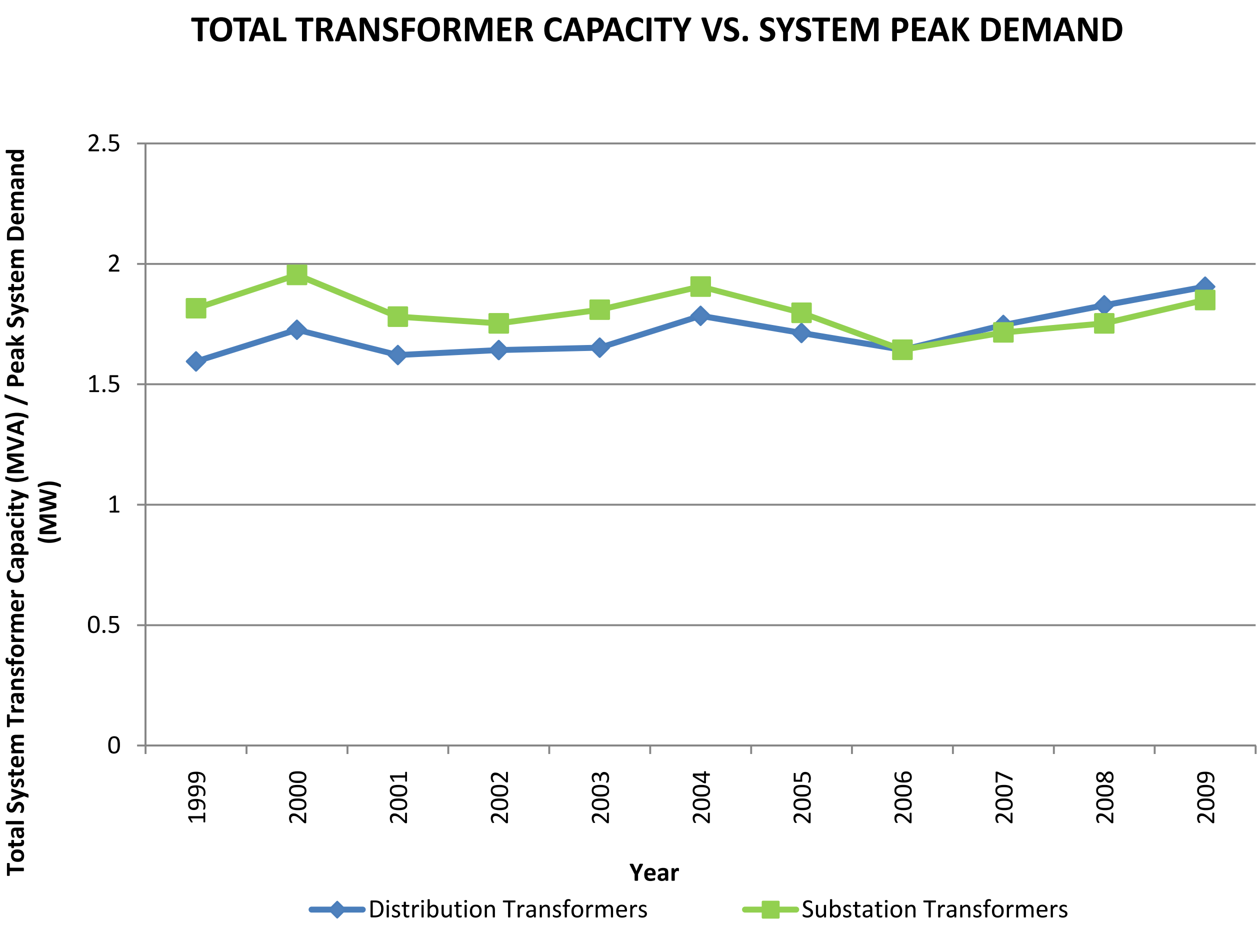


Table 1

ENGINEERING/OPERATIONS
TRANSFORMER SUMMARY
2009

Size (KVA)	RPU Transformers in Use	RPU Transformers in Stock	Customer Transformers In Use	Total Transformers in Use	Total KVA in Use
5	14	2	0	14	70
10	494	23	0	494	4940
15	758	30	0	758	11370
25	1868	39	0	1868	46700
37.5	2033	45	0	2033	76237.5
45	16	3	0	16	720
50	1192	51	0	1192	59600
75	403	44	0	403	30225
100	87	9	0	87	8700
112.5	87	5	0	87	9787.5
150	162	12	0	162	24300
167.5	7	4	0	7	1172.5
225	93	9	1	94	21150
250	0	0	3	3	750
300	86	9	0	86	25800
500	90	5	7	97	48500
750	50	4	0	50	37500
1000	20	3	1	21	21000
1500	15	1	1	16	24000
2000	4	0	0	4	8000
2500	10	2	2	12	30000
3500	2	0	0	2	7000
	7491	**300**	**15**	**7506**	**497522.5**

Customer Owned 11,975
RPU Owned Transformers 485,547.5

VII. OPERATIONS SUMMARY

A. Number of Capacitors

1. Total 13.8kV capacitance in service (12/31/2009)	84,000 KVAR
2. Capacitance installed in 2009 prior to peak	1,2000 KVAR

(There are no PCB contaminated capacitors on the RPU system.)

B. Electric Customers

	2006	2007	2008	2009
Industrial	2	2	2	2
Commercial	4,501	4,519	4,540	4,546
Residential	41,926	42,429	42,861	43,123
Streetlighting & Highway	3	3	3	3
Interdepartmental	1	1	1	1
Total Electric Customers	46,433	46,954	47,406	47,675

This customer count data is shown as weighted annual averages as reported to U.S. Dept. of Energy on Form EIA-861.

C. Historical/Current Year Records

Historical		
System Net Peak (winter) MW	192	12/15/2008
System Net Peak (summer) MW	288.4	7/31/2006
System Net Energy For Load-Max Day (kWh)	5,745,332	7/31/2006
System Net Energy For Load-Max Month (kWh)	142,094,781	7/1/2006

Current		
System Net Peak (winter)	188.9	12/10/2009
System Net Peak (summer)	261.1	6/23/2009
Maximum Day	4,714,905	8/14/2009
Maximum Month	116,729,253	8/1/2009

D. Yearly System Data (MWH)

	2006	2007	2008	2009
Steam	250,879	287,113	196,145	44,826
Hydro	13,359	15,581	13,002	9,678
Combustion Turbine	42,522	69,233	25,806	12,200
Total System Generation	306,760	371,927	234,954	66,726
Purchased Power (Scheduled)	1,283,189	1,345,417	1,324,665	1,235,081
System Net Energy for Load	1,296,548	1,360,998	1,328,421	1,255,260
System Net Peak (MW)	288.4	276.3	270.4	261.1

E. Estimates For Next Year

System Net Energy For Load (MWH)	1,355,000
Monthly Consumption (Peak)	142,000
Peak Demand (MW)	295,400

Figure 3

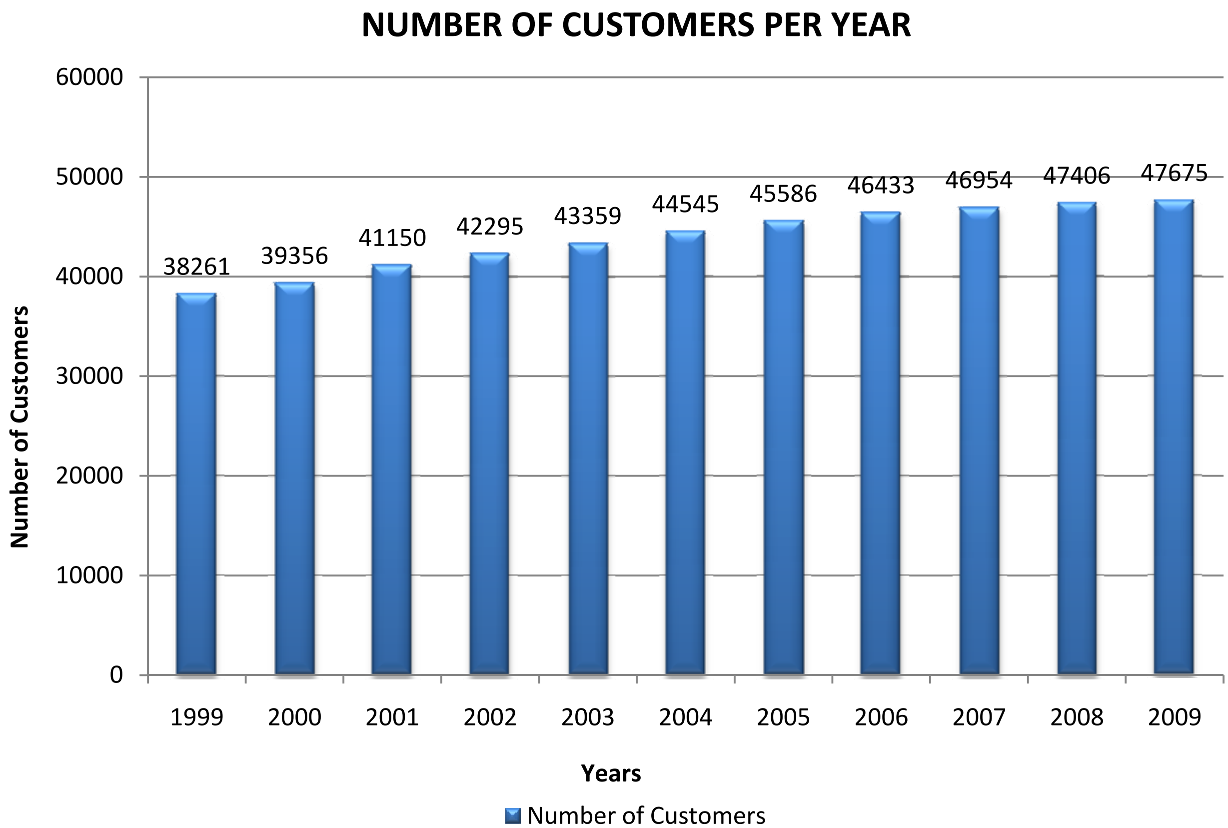


Figure 4

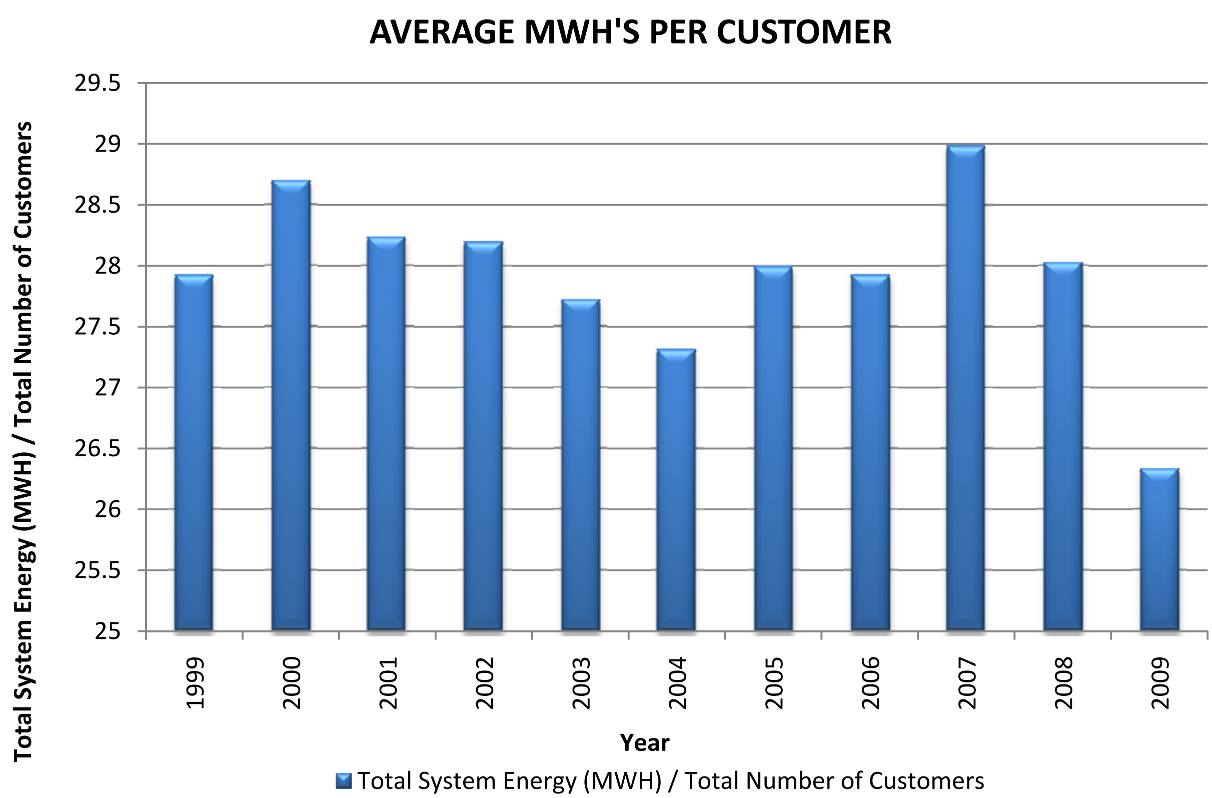
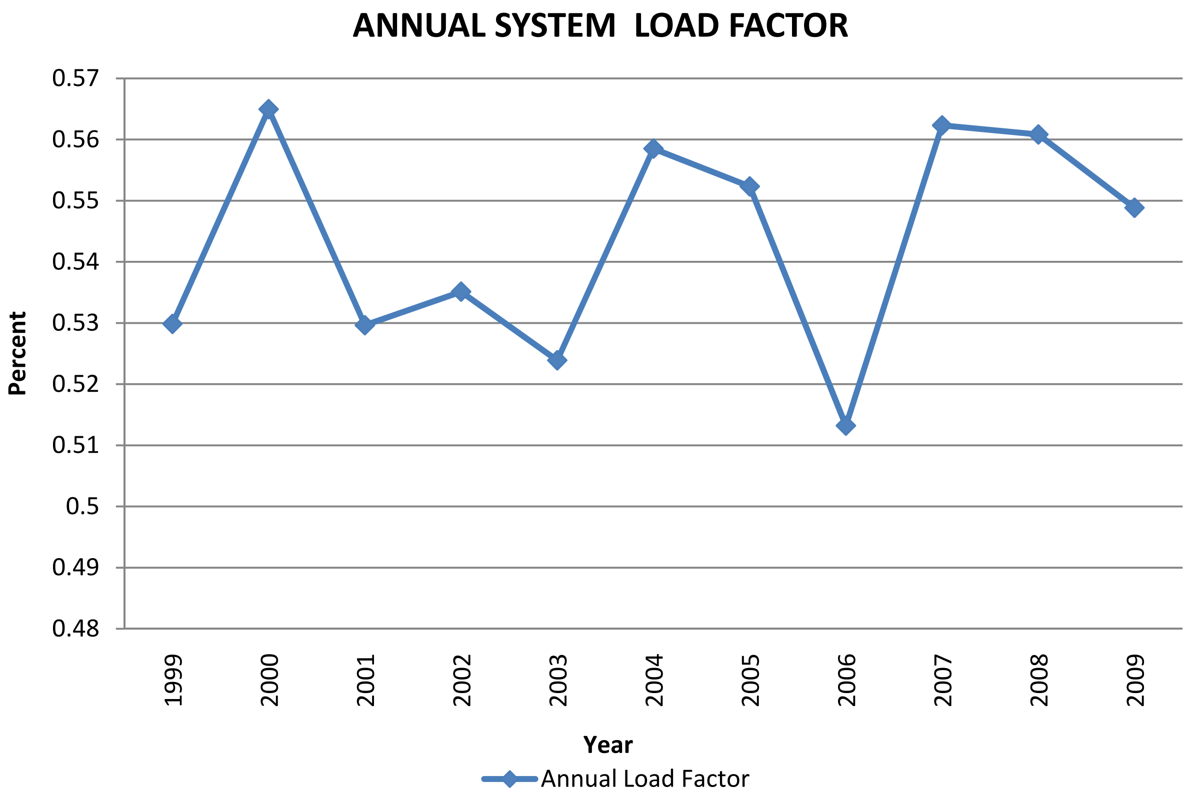


Figure 5


ANNUAL SYSTEM LOAD FACTOR
0.57
0.56
0.55
0.54
0.53
0.52
0.51
0.5
0.49
0.48
Percent
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
Year
Annual Load Factor

F. System Reliability Statistics

Please refer to Figure 6 and Section G for system reliability statistics and trends.

AVERAGE SERVICE AVAILABILITY INDEX – ASAI
The ASAI index is the ratio of total customer hours that service was available divided by the total customer hours demanded in a time period. The formula to calculate ASAI is:

$$ASAI = \frac{[(\text{customer-hours demanded}) - (\text{customer hours off})]}{(\text{customer-hours demanded})} \times 100$$

customer-hours = (12-month average number of customers) x 8760 hours demanded

The unit of ASAI is percent, and is generally carried out to four decimal places (such as: 99.9986%). A common usage of ASAI is: "the efficiency of the distribution system to deliver electric energy to our customer is _____%"

CUSTOMER AVERAGE INTERRUPTION DURATION INDEX – CAIDI
CAIDI is the weighted average length of an interruption for customers affected during a specified time period. The formula to determine this average is:

$$CAIDI = \frac{\text{sum of customer-minutes off for all sustained interruptions}}{\text{Total \# of customers affected by the sustained interruptions}}$$

The unit of CAIDI is minutes. A common usage of CAIDI is: "The average customer that experiences an outage on the distribution system is out for ___________ minutes."

SYSTEM AVERAGE INTERRUPTION DURATION INDEX – SAIDI
SAIDI is defined as the average duration of interruptions for customers served during a specified time period. Although similar to CAIDI, the average number of customers served is used instead of number of customers affected. The formula used to determine SAIDI is:

$$SAIDI = \frac{\text{sum of customer-minutes off for all interruptions}}{\text{Total \# of customers served}}$$

The unit of SAIDI is minutes. A common usage of SAIDI is: "If all the customers on the distribution system were without power the same amount of time, they would have been out for _________ minutes".

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX – SAIFI
SAIFI described the average number of times that a customer's power is interrupted during a specified time period. "SAIFI-short" is calculated using the number of customers affected by momentary interruptions (such as brief breaker or recloser operations). "SAIFI-long" is calculated using the number of customers affected by sustained interruptions.

$$\text{SAIFI-long} = \frac{\text{total \# of customers affected by sustained interruptions}}{\text{Average number of customers served}}$$

$$\text{SAIFI-short} = \frac{\text{total \# of customers affected by momentary interruptions}}{\text{Average number of customers served}}$$

The units for SAIFI are "interruptions per customer". A common usage of SAIFI is: "On the average, customers on the distribution system experienced _______ interruptions".

System Performance Measures & Reliability Indices

Year	ASAI (%)	CAIDI (Minutes)	SAIDI (Minutes)	SAIFI LONG (Interruptions/Customer)	SAIFI SHORT (Interruptions/Customer)
1994	99.9909	14.06	47.76	1.22	2.18
1995	99.9829	41.82	89.99	1.35	0.80
1996	99.9960	15.39	20.96	0.37	0.99
1997	99.9957	17.14	22.65	0.44	0.88
1998	99.9205	113.48	417.84	2.30	1.39
1999	99.9815	36.50	97.26	1.25	1.41
2000	99.9962	15.62	20.11	0.64	0.65
2001	99.9937	13.93	33.01	0.89	1.47
2002	99.9916	47.19	44.16	0.94	2.33
2003	99.9943	30.01	30.28	1.01	0.31
2004	99.9936	52.29	33.99	0.65	0.83
2005	99.9934	46.15	34.88	0.76	0.37
2006	99.9862	99.30	72.47	0.73	0.27
2007	99.9899	65.41	53.23	0.81	0.30
2008	99.9936	69.01	33.59	0.49	0.48
2009	99.9892	80.24	56.90	0.71	0.27
Overall Averages	99.9875	42.35	65.96	0.94	1.12

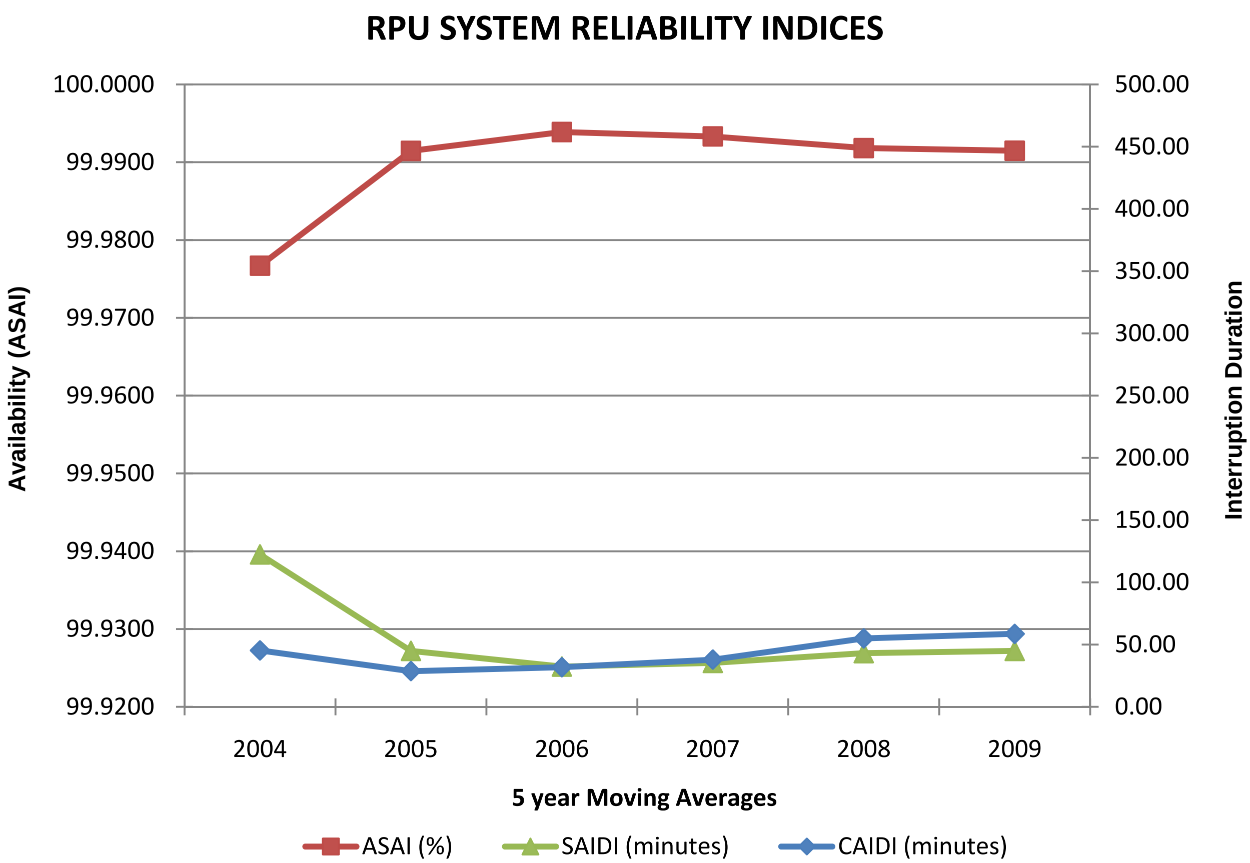
Five-Year Moving Averages

Year	ASAI (%)	CAIDI (Minutes)	SAIDI (Minutes)	SAIFI LONG (Interruptions/Customer)	SAIFI SHORT (Interruptions/Customer)
1997	99.9917	19.50	43.64	0.86	1.60
1998	99.9772	40.38	119.84	1.14	1.25
1999	99.9753	44.87	129.74	1.14	1.09
2000	99.9780	39.62	115.76	1.00	1.06
2001	99.9775	39.33	118.17	1.10	1.16
2002	99.9767	45.34	122.48	1.20	1.45
2003	99.9915	28.65	44.96	0.95	1.23
2004	99.9939	31.81	32.31	0.83	1.12
2005	99.9933	37.91	35.26	0.85	1.06
2006	99.9918	54.99	43.16	0.82	0.82
2007	99.9915	58.63	44.97	0.79	0.42
2008	99.9913	66.43	45.63	0.69	0.45
2009	99.9905	72.02	50.21	0.70	0.34

NOTES:
1. Record-keeping methods for performance statistics were standardized during late 1986.
2. All outages of 1 minute or less, even instantaneous recloses of a temporary fault are recorded as 1-minute outages.
3. In 1998, Rochester experienced a complete blackout due to failure of transmission systems of DPC and NSP during a severe storm.
4. In 1999, Rochester experienced a partial blackout due to loss of a mile of 161kV line and relaying problems.
5. In 2006 RPU switched from a manual system to an automated process using outage management software to respond to and track outages. The statistics are all inclusive for all types of outages, including TD Major and Planned Outages.

Figure 6 displays the five-year moving averages of three important system performance measurements. Trends that show generally high average service availability index (ASAI) and low customer average and system average interruption duration indices (CAIDI and SAIDI) are desirable. In 2009, ASAI decreased very slightly (99.9913 to 99.9905%, SAIDI increased 10% (45.63 to 50.21 minutes), and CAIDI increased 8.4% (66.43 to 72.02 minutes) from 2008 values.

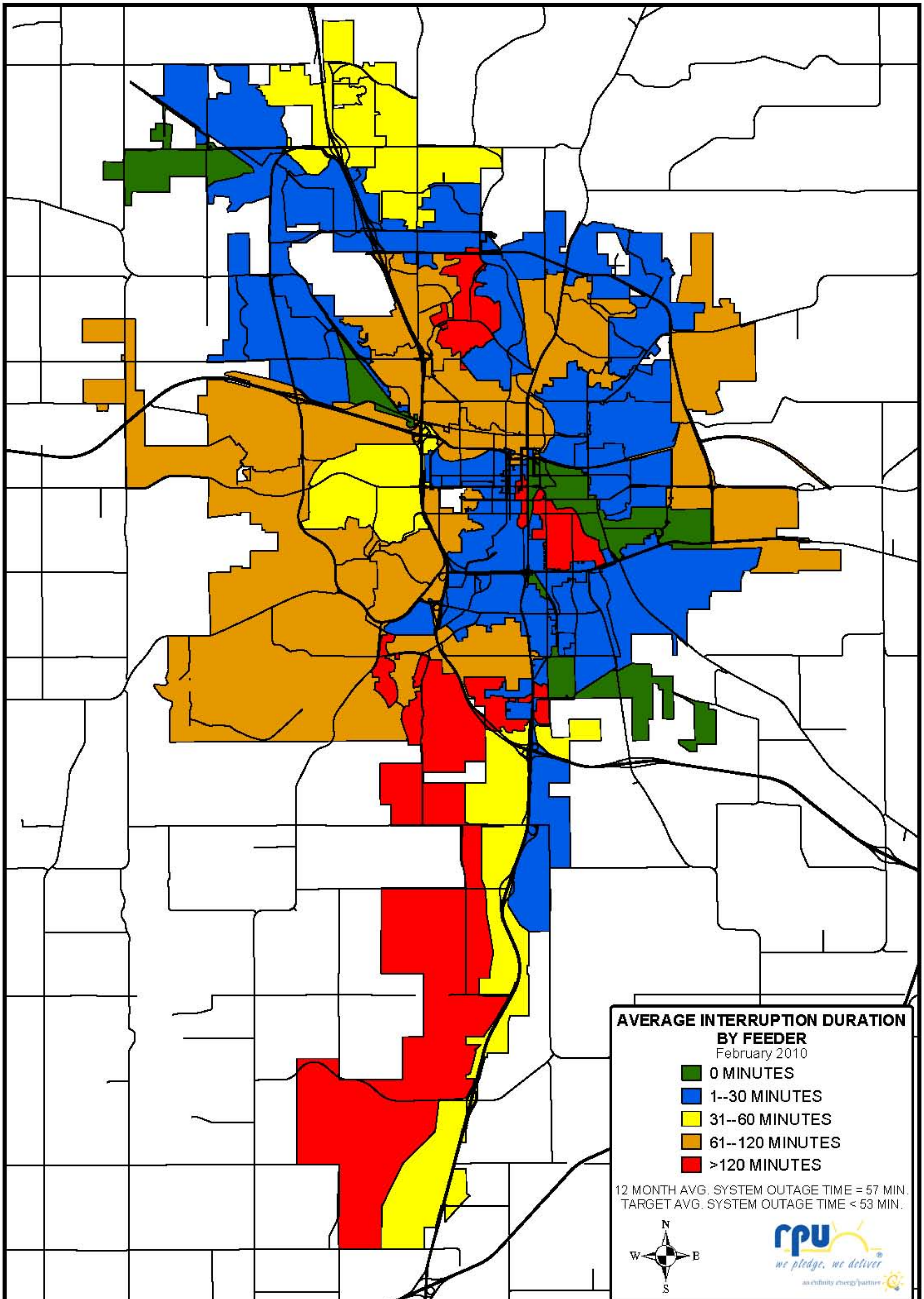
Figure 6



G. Estimated Number of Customers Per Feeder

Feeder ID	Customers	Feeder Dedicated to
207	0	
301	1173	
302	471	
303	627	
304	1076	
305	1551	
401	1173	
402	1948	
403	0	
404	156	
405	2058	
406	1	Marigold Foods
601	272	
602	18	
603	624	
604	642	
605	1555	
611	376	
612	865	
613	471	
614	2738	
701	839	
702	575	
703	2108	
704	989	
705	33	
711	750	
712	2051	
713	1207	
714	275	
715	0	
801	2190	
802	1	Water Rec Plant
803	1695	
804	1279	
805	1209	
811	1	Water Rec Plant
812	2048	
813	1097	
814	960	
815	7	
901	1926	
902	1057	
903	322	
904	771	
905	1722	
1301	1147	
1302	683	
1303	466	
1304	205	
1311	934	
1312	1173	
1313	1	
1401	1	Mayo
1402	1	Mayo
1404	1	Mayo
1411	1	Mayo
1412	1	Mayo
1413	1	Mayo
1414	1	Mayo
Total	**47,523**	

*NOTE: Customers such as Seneca Foods and IBM have many meters, but are considered as one service location.


AVERAGE INTERRUPTION DURATION
BY FEEDER
February 2010
0 MINUTES
1--30 MINUTES
31--60 MINUTES
61--120 MINUTES
>120 MINUTES
12 MONTH AVG. SYSTEM OUTAGE TIME = 57 MIN.
TARGET AVG. SYSTEM OUTAGE TIME < 53 MIN.
N
W
E
S
we pledge, we deliver

VIII. POWER PRODUCTION DATA

2009
POWER PLANT PRODUCTION REPORT

	SLP UNIT #1	SLP UNIT #2	SLP UNIT #3	SLP UNIT #4	SILVER LAKE PLANT	GAS TURBINE 1	GAS TURBINE 2	HYDRO
GROSS GENERATION KWH	561,000	7,657,000	2,618,000	41,489,000	52,325,000	N/A	N/A	N/A
NET GENERATION KWH (IN SERVICE)	343,670	6,862,626	2,256,325	36,955,375	40,971,418	770640	11429310	N/A
NET GENERATION KWH (TOTAL)	-1,490,595	5,492,405	2,038,000	35,138,200	41,178,010	770640	11429310	9678400
Btu/KWH GROSS *	35831	9226	22639	11105	30046	16961	10580	N/A
Btu/KWH NET (IN SERVICE) *	58489	10294	26268	12467	33732	16961	10580	N/A
CAPACITY FACTOR	0.89	24.98	1.19	7.55	7.65	0	2.61	39.42
AVAILABILTY FACTOR	84.96	91.47	74.11	81.18	82.93	95.52	58.86	100
FORCED OUTAGE FACTOR	0.52	2.18	1.23	2.51	1.61	0.39	28.53	0
COAL CONSUMPTION TONS--Adjusted	143	26753	2282	19984	49162	N/A	N/A	N/A
GAS CONSUMPTION MCF	16691	120015	7821	28481	173150	11551	119860	N/A
OIL CONSUMPTION GAL.	N/A	N/A	N/A	N/A	N/A	10154	453	N/A

* ACTUAL COAL USE

B. Miscellaneous

1. Coal Summary – Tons

Beginning Inventory January 1		67630.110
2009 Shipments		
Black Beauty Mine	3,041.185	
Monterey Coal	10,318.530	
River Trading Coal	37,947.830	
Total Shipments		51,307.545
Available for Burn		118,937.655
Total Tons of Coal Burned (Adjusted)		49,249.580
Ending Inventory – December 31		69,688.075

2. Steam Summary (Silver Lake Plant)

Total Steam Generated	636514 Mlb

Figure 7, Annual Minimum & Maximum Demands, shows the ten-year trend for annual peak demand. Historically, this trend showed a 5 to 6 MW per year increase in the system demand. During the late 1980s through the mid 1990s the increase in peak demand showed roughly 3 MW per year. This slow down was due to a number of factors, including interim service by PCS and the installation of co-generation equipment at Mayo Foundation's St. Mary's power plant in 1996. The maximum system demand decreased this year from 270.4 MW in 2008 to 261.1 MW in 2009. This decrease was a result of energy conservation, cooler than average temperatures in June, July and August, as well as reduced development activity.

Figure 7

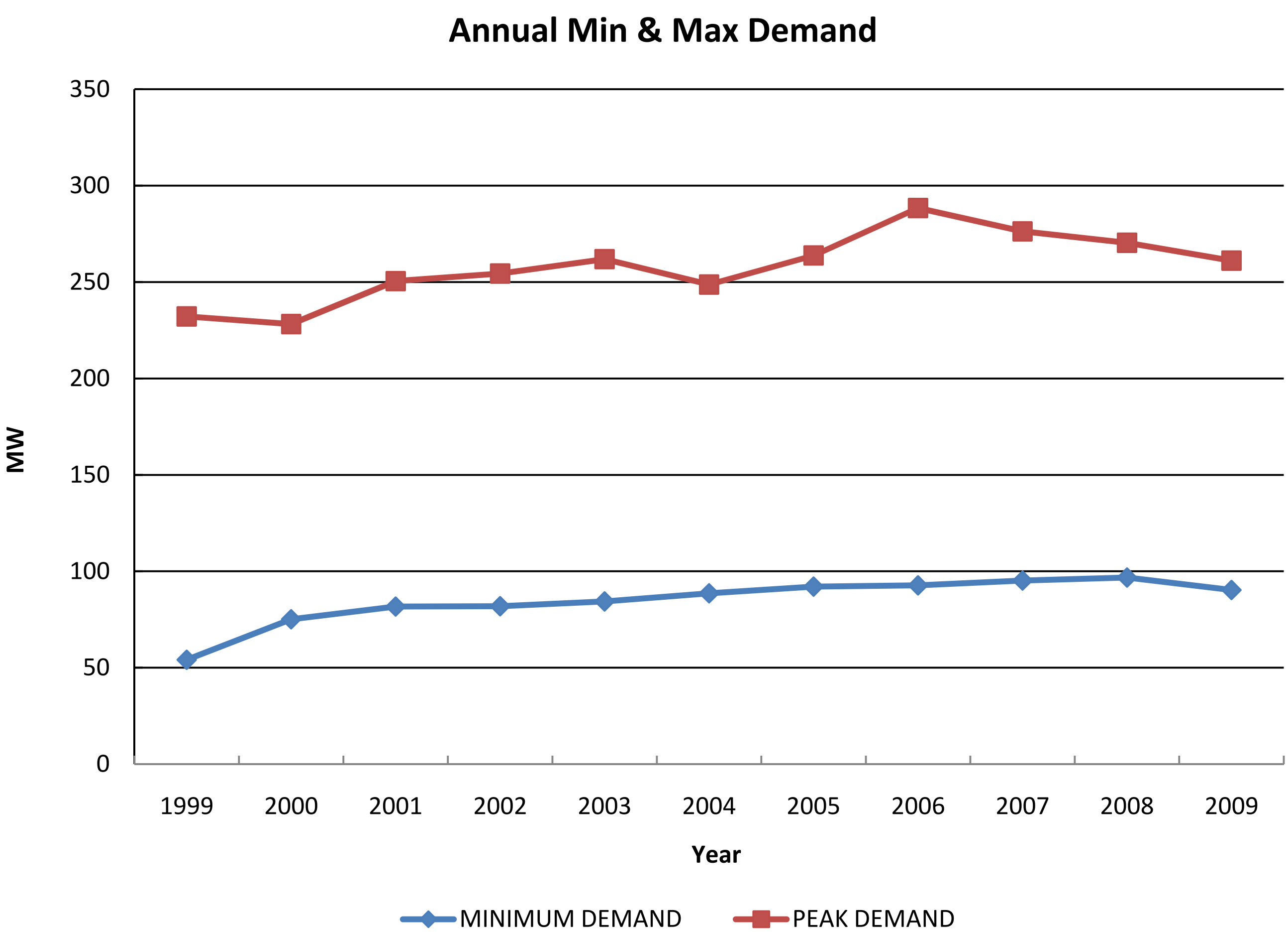
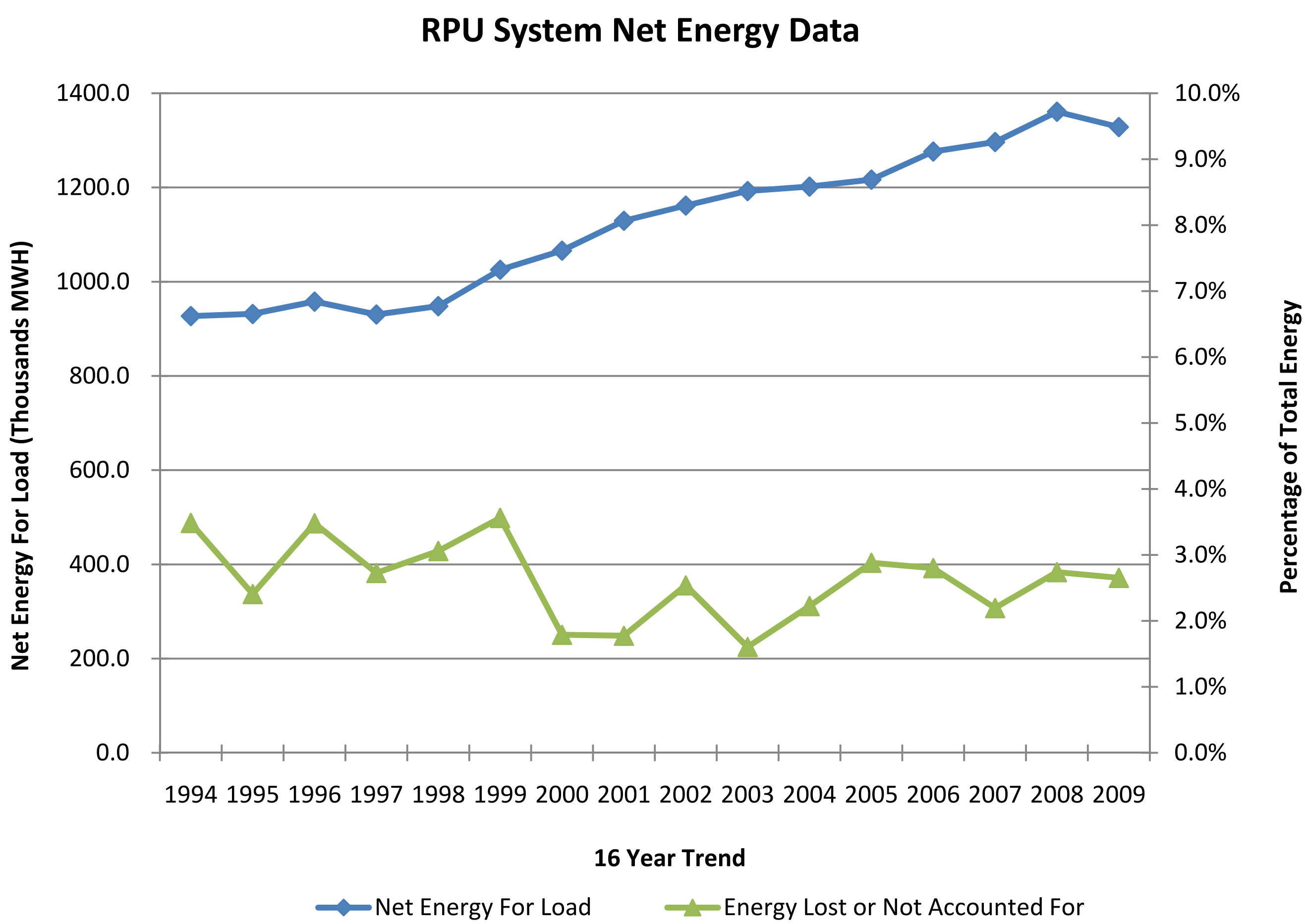


Figure 8, RPU System Net Energy Data, shows both the system net energy for load and the energy lost and unaccounted for, or system losses for 1994 through 2009. For the 16 years shown, system net energy for load rises an average of 2.17% while demand rises an average of 2.79% per year for the 1994 to 2009 period. In 2008, the net energy for load and the system peak were -2.4% and -2.1% respectively. In 2009, net energy for load decreased 5.5% and system peak decreased 3.4%

System losses and unaccounted for energy. as a percentage of total energy, has decreased from 2.6% in 2008 to 2.0% in 2009. The amount of system loss and unaccounted for energy is below the historical average of 3.0%.

Figure 8



IX. ENVIRONMENTAL/REGULATORY ACTIVITIES

Regulatory Compliance /Inspections
RPU facilities were generally operated in compliance with applicable environmental regulations and permit conditions. There were no excursions of excess sulfur dioxide (SO_2) emissions at RPU's generating facilities. No NOVs were issued for environmental non-compliance.

Permits
No changes in either the SLP or Cascade Creek air emission permits occurred in 2009.

Acid Rain Control Regulations
Unit 4 at the Silver Lake Plant and CT2 & CT3 at the Cascade Creek facility is subject to the federal Acid Rain program and must meet sulfur dioxide (SO_2) and emissions requirements. SO_2 mass emissions are limited by the number of SO_2 allowances allocated. The annual SO_2 allocations for SLP Unit 4 are 3,126 tons. In 2009, RPU retained all of its surplus SO_2 allowances and emitted 56 tons of SO_2 from SLP Unit 4.

Clean Air Interstate Rule (CAIR) Regulations
Effective December 3, 2009, EPA exempted the State of Minnesota from having to comply with the CAIR in Minnesota because the Federal Courts held that EPA had not addressed possible errors in the analysis that was used to include Minnesota in the Rule. This exemption releases RPU from having to hold CAIR SO2 and NOx allowances for compliance purposes. Minnesota may be subject to regulations under revisions to the vacated CAIR.

Clean Air Mercury Rule (CAMR) Regulations
EPA is developing air toxics emissions standards for power plants under the Clean Air Act, consistent with the February 2008 D.C. Circuit Court's opinion regarding the vacatur of the Clean Air Mercury Rule (CAMR). EPA intends to propose air toxics standards for coal- and oil-fired electric generating units by March 2011 and finalize a rule by November 2011. In this regard, EPA approved an Information Collection Request (ICR) on December 24, 2009 requiring all US power plants with coal-or oil-fired electric generating units to submit emissions information for use in developing air toxics emissions standards. RPU will be complying with this request in the first quarter 2010.

Continuous Emissions Monitoring Systems (CEMS)
Relative accuracy test audits (RATAs) of CEMS were performed on the analyzers monitoring Units 1, 2 & 3 at SLP during 2009. All results were less than 13% relative difference. An annual RATA is necessary if the relative difference is >15% and ≤20%. If the relative difference is ≤15%, RATAs may be performed biannually. Thus, the next RATAs on the analyzers monitoring Units 1, 2 & 3 are not needed until the first half of 2011. RATAs on the analyzers for Unit 4 at SLP and CT-2 and CT-3 at Cascade Creek were not necessary due to their minimal operations in 2009.

Hydro Operations

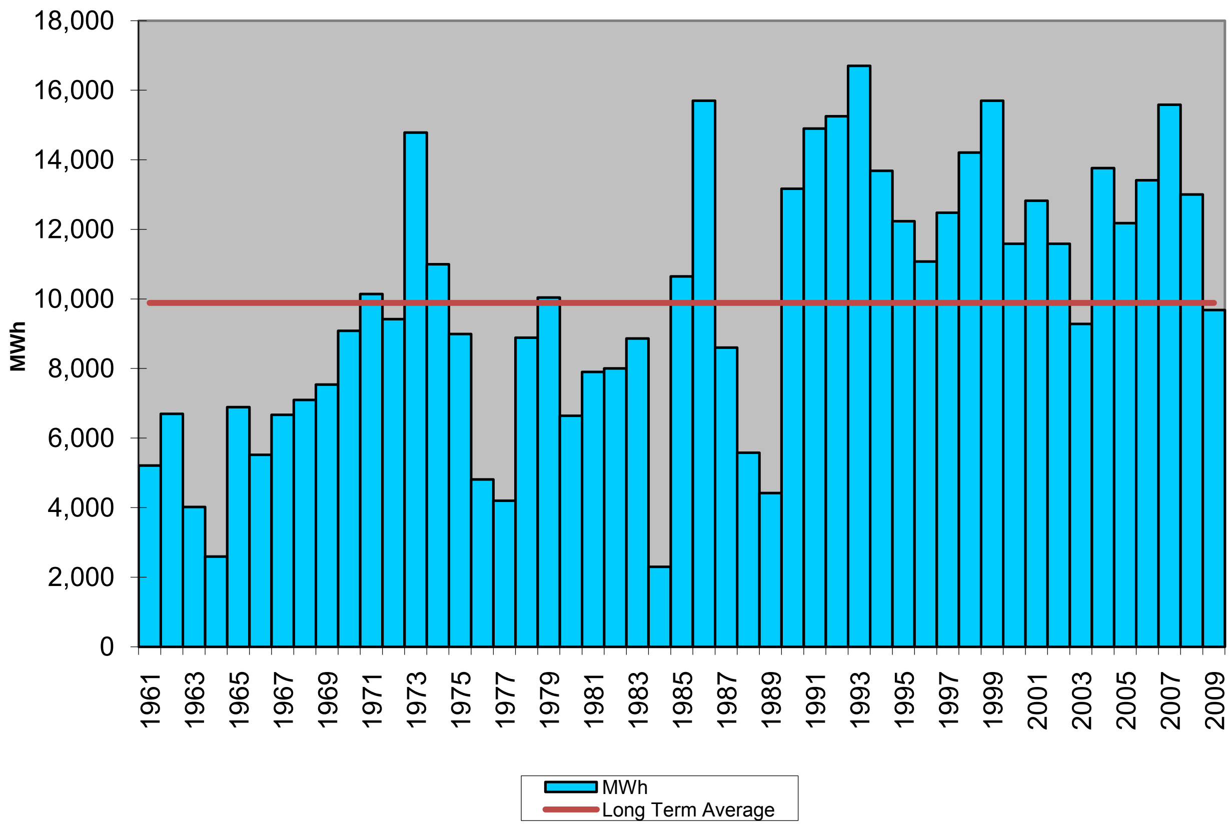
The Zumbro Hydro Plant produced 9,679 MWh of energy during 2009. This is slightly below the long-term average for the Hydro facility.

ANNUAL HYDROELECTRIC GENERATION

YEAR	MWh	YEAR	MWh	YEAR	MWh	YEAR	MWh
1961	5,208	1974	10,998	1987	8,600	2000	11,586
1962	6,697	1975	8,990	1988	5,576	2001	12,824
1963	4,020	1976	4,809	1989	4,419	2002	11,586
1964	2,590	1977	4,198	1990	13,169	2003	9,280
1965	6,887	1978	8,886	1991	14,896	2004	13,763
1966	5,517	1979	10,041	1992	15,252	2005	12,177
1967	6,666	1980	6,639	1993	16,702	2006	13,412
1968	7,095	1981	7,901	1994	13,683	2007	15,582
1969	7,539	1982	8,002	1995	12,232	2008	13,002
1970	9,084	1983	8,860	1996	11,075	2009	9,679
1971	10,139	1984	2,297	1997	12,478		
1972	9,417	1985	10,649	1998	14,206		
1973	14,784	1986	15,698	1999	15,696		

AVERAGE 9,892

Figure 9



2009 Silver Lake Plant Air Emissions Report

Hours of Operation	Unit 1	Unit 2	Unit 3	Unit 4	Total
Total Hours	300	7,899	470	1,566	10,235
Fuel Use					
Tons of Coal Burned	140.96	26,326.61	2,258.00	19,725.55	48,451
MMCF of natural Gas Burned	16.80	119.75	7.82	28.42	172.80
Heat Input					
MMBtu's of Coal Burned	3,168	584,982	51,260	433,777	1,073,186
MMBtu's of Gas Burned	17,140	122,148	7,977	28,989	176,255
Total Heat Input	20,308	707,130	59,237	462,767	1,249,441
Fuel Characteristics					
MMBtu per MCF of Natural Gas	1,020	1,020	1,020	1,020	1,020
Average Percent Ash - Coal	11.66	9.58	9.31	9.61	10.04
Average MBtu/Lb - Coal	11,236	11,110	11,351	10,995	11,075
Average Percent Sulfur - Coal	0.76	0.84	0.84	0.85	0.82
Average Moisture - Coal	11.22	13.04	12.31	13.76	12.58
Emissions					
SO2 Emission Rate lb/mmbtu	0.54	1.13	0.56	0.19	0.60
Tons of SO2 Emissions (CEMS)	5.36	396.56	16.69	42.90	461.50
Tons of SO2 Emissions (Test Dat	2.04	420.09	35.90	318.34	776.37
Tons of SO2 Emissions (Pt75)				56	
Tons of CO2 Emissions (Pt75)				49,904	
Tons of NOx Emissions (Pt75)				64	
Tons of NOx Emissions	3.90	306.36	25.93	220.96	557.15
Tons of CO Emissions	0.74	11.61	0.89	6.13	19.37
Tons of VOC Emissions	0.05	1.12	0.09	0.67	1.93
Tons of TSP Emissions	0.49	65.09	5.41	48.67	119.66
Tons of PM-10 Emissions	0.15	27.03	2.64	11.50	41.30
Tons of Lead Emissions	0.00	0.17	0.01	0.13	0.31

2009 Silver Lake Plant Air Emissions Compliance Summary

	Stack 1/2	Unit 1	Unit 2	Unit 3:	Unit 4
Hours On line	7966	300	7899	470	1566

SO2 LbPerMbtu 1 Hour Exceedances	0			0	0
Hours of CEMS Downtime	61			0	96

Opacity 6 Minute Exceedances	416			15	1
Hours with Opacity 6M Exceedances	245			10	1
Number of Opacity 6M Violations	171			5	0
COMS Downtime 6M Periods	74			1	6

TACWEF 1H Exceedances:	0	Unit 4 NOx lb/mmbtu:	0.279

Calibration Failures	41			2	709
Calibration Warnings	143			6	57

U4 SO2 Allowances	Allotted:	22,710	Used:	14,444		Available:	8,266
For the year 2009 (100%)	Allotted:	3,126	Used:	56	2%	Available:	3,070

2009 Cascade Creek Air Emissions Compliance Summary

	CT2		CT3		U1		Facility
Hours On	355		259		47		661
Hours On Gas	279		211		28		518
Hours On Oil	0		0		4		5
Operating Time - hrs	279.52		211.07				
Gas - 100 scf	758,770		589,955		109,987		1,458,713
Oil - gallons	1,150		11		10,266		11,428
NOx - Tons	2.7887		2.0570		1.0185		5.8643
NOx - ppmvdc*	173	3	132	1			
CO - Tons	11		11		0		21
SO2 - lbs/hr*	2	0	0	0	16	0	
NOx Control - (Water Injection) - lbs	56,133		42,642				98,775

* Maximum Value for time period

ROCHESTER PUBLIC UTILITIES
ELECTRIC OPERATING PERMIT FEES

Agency	Permit or Fee	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
		Annual Fee Amount									
MPCA	SLP - Air Emission	98,133	73,299	96,954	107,248	47,193	138,643	138,231	130,571	127,677	164,652
	SLP – NPDES*	13,000	13,000	13,000	16,900	1,230	1,230	1,580	1,230	1,230	1,230
	SLP – Haz. Waste Generator	188	188	198	205	235	420	411	413	425	453
	CCGT – Air Emission	491	581	2,782	935	658	293	156	403	827	1,859
	SC – Haz. Waste Generator	756	756	198	205	1,421	420	0	683	425	425
	SC – Air Emissions Fee	0	0	0	0	0	0	0	0	0	0
	Storm Water (SLP, CCCT & SC)	630	630	630	840	840	800	800	800	800	800
	RPU/IBM GenSet Air Emissions Fee	0	0	0	0	1,626	0	0	25	61	25
	Toxic Pollution Prevention Fee (TRI)		5,597	9,001	3,128	7,963	9,363	9,509	8,228	7,454	8,500
MN/DNR	**SLP – Water Appropriation	26,041	36,623	41,436	24,873	78,522	73,396	78,313	62,529	71,889	66,353
	Power Line License Fees	0	40	285	1,976	2,585	7,612	0	1,507	0	0
MN DOC/PUC	Assessment-PPSP/ADCP/EFA	7,123	9,580	6,998	14,892	6,436	6,934	8,799	14,808	14,474	18,543
DPS/ERC	SARA 313 Annual Fee - SLP		800	800	800	800	800	800	800	800	800
	SARA (SLP, CCCT & SC)	225	225	225	225	225	225	225	225	450	225
ANNUAL TOTAL		147,387	142,079	172,508	172,227	149,733	240,135	238,824	222,223	226,512	263,864
Percent Change from Previous Year		5%	-4%	21%	0%	-13%	60%	-1%	-7%	2%	16%
Cost of Permits / Capacity KW***		1.03	0.99	0.92	0.91	0.79	1.26	1.26	1.17	1.19	1.39

Notes:
* Discharge Fees were included prior to 2004
**Beginning in 2005, a $20/Mgal surcharge was applied to the volume of water discharged in months of June, July & Augst that exceeded volume used in Jan.
***Non-hydro capacity standardized at 190,000 kW.

SUMMAY OF TOTALS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Water Appropriation Fees	26,041	36,623	41,436	24,873	78,522	73,396	78,313	62,529	71,889	66,353
Air Emission Fees	98,624	73,880	99,736	108,183	49,477	138,935	138,388	130,999	128,566	166,536
Other Operating Fees	22,722	31,576	31,335	39,171	21,735	27,804	22,123	28,695	26,058	30,976
CE 504003 - Water Appropriations	26,041	36,623	41,436	24,873	78,522	73,396	78,313	62,529	71,889	66,353
CE 504004 - Utility Licenses, Permits, and Fees	120,546	104,697	131,072	147,354	71,211	166,739	160,511	159,694	154,623	197,511