LICKING VALLEY
RURAL ELECTRIC COOPERATIVE CORPORATION
P. O. Box 605 • 271 Main Street
West Liberty, KY 41472-0605
(606) 743-3179

April 6, 2005

Ms. Beth O'Donnell, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P O Box 615
Frankfort, KY 40602

RE: Administrative Case No. 2005-00090
An Assessment of Kentucky's Electric Generation, Transmission
And Distribution Needs

Dear Ms. O'Donnell:

Please find enclosed the original and ten (10) copies of the information requested in Administrative Case No. 2005-00090. The information requested is A Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs for Licking Valley Rural Electric Cooperative Corporation.

If you have any additional questions please feel free to contact our office.

Sincerely,

Larry R. Easterling
Superintendent: Operations Department

LRE: dbr

Enclosures

c: Bill Duncan
Kerry Howard

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This is the Service List for Case 2005-00090

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This is the Service List for Case 2005-00090

Licking Valley Rural Electric Cooperative Corporation
Response
Item 1

1. Provide a summary description of your utility's resource planning process?

Licking Valley Rural Electric Cooperative Corporation is a distribution cooperative. It does not have any generation or transmission facilities.

Licking Valley Rural Electric Cooperative Corporation's distribution resource planning is conducted along guidelines is in compliance with Rural Utilities Service. Licking Valley Rural Electric Cooperative Corporation's current construction work plan was implemented in the year 2001 and continues through the year 2005. Licking Valley Rural Electric Cooperative Corporation's long -range work plan is for a twenty (20) year period. Our long-range work plan was adopted in the year of 1998. However, before this plan is to expire, we will probably reevaluate this in the year of 2008. This reassessment will ensure that requirements are being achieved.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 2

2. Are new technologies for improving reliability, efficiency and safety investigated and considered for implementation in your power generation, transmission and distribution system?

Yes

a. If yes, discuss the new technologies that were considered in the last five (5) years and indicate which, if any, were implemented?

Licking Valley Rural Electric Cooperative Corporation does explore new technologies, researches, evaluates and utilizes those that have had a constructive outcome. Included in this subject matter are:

1. Automatic Meter Reading: Automatic Meter Reading (known as AMR's) was presented to Licking Valley Rural Electric Cooperative Corporation by way of Hunt Technologies. This has first and foremost proven to have affirmative reactions from our consumers; the benefit of this technology is that our consumers do not have to read and report their meter readings. From Licking Valley Rural Electric Cooperative Corporation's perspective we are now capable of distinguishing if an account has been illegally connected. A second advantage has been consumer billing resolutions.

2. Smart Switch: In a joint effort between Licking Valley Rural Electric Cooperative Corporation and Power Quality Systems, Licking Valley Rural Electric Cooperative Corporation does now have one (1) "Smart Switch" on line in a remote area with large commercial load at the end of this circuit; this has improved power quality to both commercial and residential consumers and a second unit at a currently disconnected location: for which this is a movable component, if considered necessary elsewhere.

3. End Line Monitors: Licking Valley Rural Electric Cooperative Corporation does have end line monitors, which scrutinize voltage.

4. System Analysis: Jim Bridges with Distribution System Solutions constantly addresses system analysis including sectionalizing studies for our cooperative.

5. Radio/ Communications System: Licking Valley Rural Electric Cooperative Corporation is in process of upgrading our radio communications. Our maintenance service personnel have mobile phones in their trucks. In addition, the majority of our construction and maintenance personnel have a pager.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 2 (continued)

Item 2

6. **Vegetation Control: Licking Valley Rural Electric Cooperative Corporation has an aggressive right of way program and has contracted WA Kendall to address our cooperatives right of way requirements. Our cooperative likes to maintain sixty - foot of right of way clearance on new and existing accounts. We have one right of way crew that will concentrate on Herbicide Treatment, principally from the months of May until August or September.**

7. **Trucks are well maintained with updated equipment to better enhance safety and productivity.**

8. **Safety: Licking Valley Rural Electric Cooperative Corporation continues on an annual basis to train their employees in First Aid, CPR and Blood Borne Pathogens. Licking Valley Rural Electric Cooperative Corporation's Operations Department has safety meetings presented to us through the Kentucky Association of Electric Cooperatives (known as KAEC).**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 3

3. **Not Applicable**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 4

4. Not Applicable

Licking Valley Rural Electric Cooperative Corporation
Response
Item 5

5. Provide actual and weather –normalized annual coincident peak demands for calendar years 2000 through 2004 disaggregated into(a) native load demand, firm and non-firm; and (b)off-system demand, firm and non-firm.

Licking Valley Rural Electric Cooperative Corporation
Actual and Weather – Normalized Annual Coincident Peak Demands
Based on Jackson Weather Station Data and Licking Valley RECC Hourly Load Data

Annual Peak	**Adjusted Peak (MW)**
December 2000	**67**
Annual Peak	**Adjusted Peak (MW)**
January 2001	**68**
Annual Peak	**Adjusted Peak (MW)**
January 2002	**69**
Annual Peak	**Adjusted Peak (MW)**
January 2003	**67**
Annual Peak	**Adjusted Peak (MW)**
January 2004	**69**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 6 through 16

6-16.

The information of which you have requested on the aforementioned item numbers can be supplied to you by Licking Valley Rural Electric Cooperative Corporation's transmission provider, which is East Kentucky Power Cooperative.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 17

17. Provide a summary description of your utilities existing demand-side management ("DSM") programs, which includes:

For the past twenty (20) years, Licking Valley RECC has offered marketing and DSM programs that has best suited the wants and needs of their customers.

Licking Valley RECC has programs to help consumers be more efficient as well as peak load reduction for both residential and commercial customers.

Licking Valley RECC has meetings regularly with local business and school leaders to help meet their needs and to supply them with the best quality service available.

The DSM programs Licking Valley RECC has been involved with are:

Geothermal Heating and Cooling Incentive Program
Tune-up HVAC Maintenance Program
Touchstone Energy Home Incentive Program
Off System Peak Load Reduction
Electric Water Heater Incentive Program
Button-up Weatherization Program
Free On-Line Energy Efficiency Profile
Safety & Efficiency Education

Commercial:

Energy Cost Control
Lighting Audits
Cost Comparisons

A. **Annual DSM Budget**
Licking Valley RECC has no existing DSM in their budget.

B. **Demand and Energy Impacts:**
Licking Valley RECC has no means of tracking energy impacts at this time.

C. **The Currently Scheduled Termination Dates for the Programs:**
Licking Valley RECC's DSM programs are on going and don't have any set dates for program termination.

Programs are to be evaluated later in 2005 to determine the effectiveness of them.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 18

18. Provide your utilities definition of "transmission and distribution".

Licking Valley Rural Electric Cooperative Corporation is a distribution cooperative that is associated with East Kentucky Power Cooperative. Licking Valley RECC begins their operation at the breaker on the low side of the substation to the consumer's point of service.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 19

19. Identify all utilities with which your utility is interconnected and the transmission capacity at all points of interconnection.

Licking Valley Rural Electric Cooperative Corporation does not have any interconnections with other utilities, with the exception of East Kentucky Power Cooperative, which is our transmission provider.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 20 through 25

20. Not Applicable

21. Not Applicable

21. Not Applicable

22. Not Applicable

23. Not Applicable

25. Not Applicable

Licking Valley Rural Electric Cooperative Corporation
Response
Item 26

26.

			2001 SAIDI	2001 SAIFI
Zachariah Sub.	**Feeder**	**1**	**.0919**	**.0795**
		2	**.0492**	**.1205**
Oakdale Sub.	**Feeder**	**1**	**.0358**	**.0192**
		2	**.0196**	**.0329**
		3	**.0671**	**.1315**
		4	**.0498**	**.0575**
Helechewa Sub.	**Feeder**	**1**	**.1469**	**.0986**
		2	**.1380**	**.1425**
		3	**.3472**	**.1507**
West Liberty Sub.	**Feeder**	**1**	**.0072**	**.0411**
		2	**.0369**	**.0575**
		3	**.0944**	**.1041**
Maggard Sub.	**Feeder**	**1**	**.0087**	**.0041**
		2	**.0203**	**.0575**
		3	**.0694**	**.0712**
Sublett Sub.	**Feeder**	**1**	**.0218**	**.0904**
		2	**.0331**	**.0795**
		3	**.2001**	**.1151**
		4	**.0091**	**.0164**
Campton Sub.	**Feeder**	**1**	**.0350**	**.0767**
		2	**.0953**	**.1945**
		3	**.0468**	**.0794**
Index Sub.	**Feeder**	**1**	**.0106**	**.0712**
		2	**.0097**	**.0247**
		3	**.0452**	**.0849**
Maytown Sub.	**Feeder**	**1**	**.0286**	**.0904**
		2	**.0129**	**.0329**
		3	**.1177**	**.0959**
Crockett Sub.	**Feeder**	**1**	**.0162**	**.0356**
		2	**.0273**	**.0630**
		3	**.0774**	**.0493**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 26

26.

2002

			SAIDI	SAIFI
Zachariah Sub.	**Feeder**	**1**	**.1191**	**.0767**
		2	**.0751**	**.1205**
Oakdale Sub.	**Feeder**	**1**	**.0186**	**.0301**
		2	**.1575**	**.0712**
		3	**.0388**	**.0904**
		4	**.0686**	**.0548**
Helechewa Sub.	**Feeder**	**1**	**.0393**	**.0767**
		2	**.1093**	**.1178**
		3	**.1701**	**.1616**
West Liberty Sub.	**Feeder**	**1**	**.0538**	**.0794**
		2	**.0385**	**.0356**
		3	**.0495**	**.1123**
Maggard Sub.	**Feeder**	**1**	**.0473**	**.0493**
		2	**.0184**	**.0329**
		3	**.0276**	**.0630**
Sublett Sub.	**Feeder**	**1**	**.0733**	**.0685**
		2	**.0297**	**.0493**
		3	**.2112**	**.1452**
		4	**.0185**	**.0219**
Campton Sub.	**Feeder**	**1**	**.0340**	**.0656**
		2	**.0830**	**.1452**
		3	**.1116**	**.0548**
Index Sub.	**Feeder**	**1**	**.0127**	**.0740**
		2	**.0044**	**.0384**
		3	**.0600**	**.1096**
Maytown Sub.	**Feeder**	**1**	**.0915**	**.1068**
		2	**.0325**	**.0438**
		3	**.0672**	**.0932**
Crockett Sub.	**Feeder**	**1**	**.0165**	**.0247**
		2	**.0208**	**.0685**
		3	**.0569**	**.0740**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 26

26.

2003

			SAIDI	SAIFI
Zachariah Sub.	Feeder	1	.0223	.0356
		2	.1002	.0877
Oakdale Sub.	Feeder	1	.0192	.0247
		2	.0659	.0603
		3	.0435	.0658
		4	.0699	.0438
Helechewa Sub.	Feeder	1	.0505	.0959
		2	.2409	.1260
		3	.0560	.1288
West Liberty Sub.	Feeder	1	.0392	.0685
		2	.0326	.0438
		3	.1081	.1233
Maggard Sub.	Feeder	1	.0071	.0274
		2	.0219	.0384
		3	.0862	.0630
Sublett Sub.	Feeder	1	.0503	.0795
		2	.0185	.0411
		3	.1063	.1342
		4	.0004	.0055
Campton Sub.	Feeder	1	.0706	.1123
		2	.1384	.1342
		3	.0673	.1096
Index Sub.	Feeder	1	.0150	.0685
		2	.0079	.0384
		3	.0902	.0959
Maytown Sub.	Feeder	1	.0631	.0849
		2	.0733	.0521
		3	.0907	.1315
Crockett Sub.	Feeder	1	.0419	.0301
		2	.0929	.0384
		3	.0221	.0575

Licking Valley Rural Electric Cooperative Corporation
Response
Item 26

26.

2004

			SAIDI	SAIFI
Zachariah Sub.	**Feeder**	**1**	**.0759**	**.0767**
		2	**.1630**	**.2247**
Oakdale Sub.	**Feeder**	**1**	**.0023**	**.0164**
		2	**.0874**	**.0822**
		3	**.0359**	**.0986**
		4	**.0238**	**.0438**
Helechewa Sub.	**Feeder**	**1**	**.2786**	**.1205**
		2	**.2188**	**.1479**
		3	**.4495**	**.1589**
West Liberty Sub.	**Feeder**	**1**	**.0343**	**.0658**
		2	**.0994**	**.0603**
		3	**.1335**	**.1178**
Maggard Sub.	**Feeder**	**1**	**.0174**	**.0630**
		2	**.0897**	**.0849**
		3	**.1884**	**.0849**
Sublett Sub.	**Feeder**	**1**	**.2204**	**.1123**
		2	**.0711**	**.0959**
		3	**.3826**	**.1726**
		4	**.0310**	**.0384**
Campton Sub.	**Feeder**	**1**	**.1069**	**.1397**
		2	**.1566**	**.1893**
		3	**.0710**	**.0877**
Index Sub.	**Feeder**	**1**	**.0249**	**.0712**
		2	**.0243**	**.0329**
		3	**.0390**	**.1342**
Maytown Sub.	**Feeder**	**1**	**.1972**	**.1452**
		2	**.1630**	**.0822**
		3	**.2053**	**.0849**
Crockett Sub.	**Feeder**	**1**	**.0078**	**.0329**
		2	**.0987**	**.0767**
		3	**.0342**	**.0849**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 27

27.

2001

			Including Major Outages SAIDI	SAIFI
Zachariah Sub.	**Feeder**	**1**	**.1471**	**.0959**
		2	**.0801**	**.1479**
Oakdale Sub.	**Feeder**	**1**	**.0358**	**.0192**
		2	**.0246**	**.0384**
		3	**.0677**	**.1397**
		4	**.0570**	**.0685**
Helechewa Sub.	**Feeder**	**1**	**.1479**	**.1068**
		2	**.1725**	**.1644**
		3	**.4213**	**.1753**
West Liberty Sub.	**Feeder**	**1**	**.0383**	**.0575**
		2	**.0407**	**.0630**
		3	**.1211**	**.1205**
Maggard Sub.	**Feeder**	**1**	**.0118**	**.0466**
		2	**.0210**	**.0603**
		3	**.0808**	**.0849**
Sublett Sub.	**Feeder**	**1**	**.0263**	**.0959**
		2	**.0401**	**.0904**
		3	**.2005**	**.1233**
		4	**.0315**	**.0192**
Campton Sub.	**Feeder**	**1**	**.0448**	**.0904**
		2	**.1014**	**.2082**
		3	**.0561**	**.0877**
Index Sub.	**Feeder**	**1**	**.0106**	**.0712**
		2	**.0102**	**.0301**
		3	**.0453**	**.0877**
Maytown Sub.	**Feeder**	**1**	**.0298**	**.0986**
		2	**.0134**	**.0384**
		3	**.1358**	**.1041**
Crockett Sub.	**Feeder**	**1**	**.0162**	**.0356**
		2	**.0279**	**.0685**
		3	**.1044**	**.0521**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 27

27.

2002

			Including Major Outages SAIDI	SAIFI
Zachariah Sub.	Feeder	1	.1191	.0767
		2	.0752	.1233
Oakdale Sub.	Feeder	1	.0264	.0329
		2	.1668	.0767
		3	.1293	.1178
		4	.0918	.0603
Helechewa Sub.	Feeder	1	.0550	.0849
		2	.2742	.1562
		3	.2026	.1781
West Liberty Sub.	Feeder	1	.0549	.0849
		2	.0386	.0384
		3	.0586	.1151
Maggard Sub.	Feeder	1	.0481	.0521
		2	.0512	.0384
		3	.0729	.0658
Sublett Sub.	Feeder	1	.3929	.0932
		2	.2643	.0630
		3	.7156	.1945
		4	.1233	.0329
Campton Sub.	Feeder	1	.0508	.0685
		2	.1131	.1616
		3	.1259	.0630
Index Sub.	Feeder	1	.0174	.0849
		2	.0312	.0521
		3	.0647	.1123
Maytown Sub.	Feeder	1	.1091	.1178
		2	.0359	.0466
		3	.0779	.0959
Crockett Sub.	Feeder	1	.0211	.0274
		2	.0208	.0685
		3	.0569	.0740

Licking Valley Rural Electric Cooperative Corporation
Response
Item 27

27.

2003

			Including Major Outages SAIDI	SAIFI
Zachariah Sub.	**Feeder**	**1**	**.0387**	**.0411**
		2	**.2924**	**.0986**
Oakdale Sub.	**Feeder**	**1**	**.0998**	**.0356**
		2	**.2192**	**.0685**
		3	**.3792**	**.0795**
		4	**.2003**	**.0548**
Helechewa Sub.	**Feeder**	**1**	**.0505**	**.0959**
		2	**.2458**	**.1315**
		3	**.0560**	**.1288**
West Liberty Sub.	**Feeder**	**1**	**.0417**	**.0767**
		2	**.0327**	**.0466**
		3	**.1376**	**.1534**
Maggard Sub.	**Feeder**	**1**	**.0071**	**.0274**
		2	**.0219**	**.0384**
		3	**.1020**	**.0658**
Sublett Sub.	**Feeder**	**1**	**.0544**	**.0822**
		2	**.0185**	**.0411**
		3	**.1063**	**.1342**
		4	**.0004**	**.0055**
Campton Sub.	**Feeder**	**1**	**.0719**	**.1178**
		2	**.1548**	**.1507**
		3	**.0673**	**.1096**
Index Sub.	**Feeder**	**1**	**.0150**	**.0685**
		2	**.0079**	**.0384**
		3	**.1068**	**.0986**
Maytown Sub.	**Feeder**	**1**	**.1133**	**.1068**
		2	**.0733**	**.0521**
		3	**.1797**	**.1507**
Crockett Sub.	**Feeder**	**1**	**.0419**	**.0301**
		2	**.0931**	**.0438**
		3	**.0394**	**.0630**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 27

27.

2004

			Including Major Outages SAIDI	SAIFI
Zachariah Sub.	Feeder	1	.1246	.0904
		2	.8941	.2849
Oakdale Sub.	Feeder	1	.0114	.0219
		2	.1340	.0932
		3	.1373	.1151
		4	.0484	.0575
Helechewa Sub.	Feeder	1	.3725	.1260
		2	.6287	.1973
		3	.5590	.1973
West Liberty Sub.	Feeder	1	.0973	.0767
		2	.1713	.0767
		3	.2364	.1315
Maggard Sub.	Feeder	1	.0277	.0685
		2	.1099	.0932
		3	.2004	.0932
Sublett Sub.	Feeder	1	.2553	.1315
		2	.0801	.1178
		3	.8565	.1890
		4	.0328	.0466
Campton Sub.	Feeder	1	.1369	.1644
		2	.1892	.2110
		3	.1857	.1068
Index Sub.	Feeder	1	.2447	.0932
		2	.0495	.0438
		3	.1264	.1562
Maytown Sub.	Feeder	1	.2447	.1507
		2	.1948	.0959
		3	.2417	.0959
Crockett Sub.	Feeder	1	.0892	.0438
		2	.1627	.1014
		3	.1182	.0959

Licking Valley Rural Electric Cooperative Corporation
Response
Item 28

28.

Licking Valley Rural Electric Cooperative Corporation persistently endeavors to improve reliability standards. However, there has been no formal adoption of an acceptable SAIDI or SAIFI.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 29

29. Provide the yearly Customer Average Interruption Duration Index ("CAIDA") and the Customer Average Interruption Frequency Index ("CAIFI"), including and excluding major outages, on your system for the last five years. What is an acceptable value for CAIDI and CAIFI? Explain how it was derived.

December 2001

	POWER SUPPLIER	MAJOR STORM	SCHEDULED	ALL OTHER	TOTAL
NUMBER OF INTERRUPTIONS					
This Month	0	19	9	58	86
This Month Last Year	0	0	8	49	57
This Year To Date	1	101	58	824	984
Last Year To This Date	10	143	137	692	982
CONSUMER-HOURS INTERRUPTION					
This Month	0	1485.75	319.83	2751.24	4556.82
This Month Last Year	0	0	208.50	2450.83	2659.33
This Year To Date	339.50	5529.15	3292.63	29143.69	38304.97
Last Year To This Date	11303.58	22712.11	5342.14	37731.96	77089.79
AVERAGE HOURS PER CONSUMER					
This Month	0	.0914	.0197	.1692	.2803
This Month Last Year	0	0	.0130	.1523	.1653
This Year To Date	. 0211	.3421	.2042	1.8063	2.3737
Last Year To This Date	.7104	1.4259	.3356	2.3692	4.8411

DATA FOR COMPUTING AVERAGE HOURS PER CONSUMER

Number of Consumers Served This Month:	16,257
Average Number of Consumers This Year To Date:	193,506/12 = 16,125

Licking Valley Rural Electric Cooperative Corporation
Response
Item 29 (continued)

December 2002

	POWER SUPPLIER	MAJOR STORM	SCHEDULED	ALL OTHER	TOTAL
NUMBER OF INTERRUPTIONS					
This Month	1	37	7	50	95
This Month Last Year	0	19	9	58	86
This Year To Date	5	89	65	797	956
Last Year To This Date	1	101	58	824	984
CONSUMER-HOURS INTERRUPTION					
This Month	3941.00	4136.16	1725.08	1482.24	11284.48
This Month Last Year	0	1485.75	319.83	2751.24	4556.82
This Year To Date	17101.66	8184.22	7195.70	28487.87	60969.45
Last Year To This Date	339.50	5529.15	3292.63	29143.69	38304.97
AVERAGE HOURS PER CONSUMER					
This Month	.2379	.2497	.1041	.0895	.6812
This Month Last Year	0	.0914	.0197	.1692	.2803
This Year To Date	1.0442	.4972	.5464	1.7443	3.8321
Last Year To This Date	.0211	.3421	.2042	1.8063	2.3737

DATA FOR COMPUTING AVERAGE HOURS PER CONSUMER

Number of Consumers Served This Month:	16,565
Average Number of Consumers This Year To Date:	196,161/12= 16,346

Licking Valley Rural Electric Cooperative Corporation
Response
Item 29 (continued)

December 2003

	POWER SUPPLIER	MAJOR STORM	SCHEDULED	ALL OTHER	TOTAL
NUMBER OF INTERRUPTIONS					
This Month	0	0	15	60	75
This Month Last Year	1	37	7	50	95
This Year To Date	4	57	124	698	883
Last Year To This Date	5	89	65	797	956
CONSUMER-HOURS INTERRUPTION					
This Month	0	0	411.91	2561.82	2973.73
This Month Last Year	3941.00	4136.16	1725.08	1482.24	11284.48
This Year To Date	13584.66	5368.91	4090.02	28608.13	51651.72
Last Year To This Date	17101.66	8184.22	7195.90	28487.87	60969.45
AVERAGE HOURS PER CONSUMER					
This Month	0	0	.0245	.1527	.1772
This Month Last Year	.2379	.2497	.1041	.0895	.6812
This Year To Date	.8215	.3254	.2456	1.7234	3.1159
Last Year To This Date	1.0442	.4972	.5464	1.7443	3.8321

DATA FOR COMPUTING AVERAGE HOURS PER CONSUMER

Number of Consumers Served This Month: 16,782

Average Number of Consumers This Year To Date: 199,163/12= 16,597

Licking Valley Rural Electric Cooperative Corporation
Response
Item 29 (continued)

December 2004

	POWER SUPPLIER	MAJOR STORM	SCHEDULED	ALL OTHER	TOTAL
NUMBER OF INTERRUPTIONS					
This Month	1	0	23	105	129
This Month Last Year	0	0	15	60	75
This Year To Date	17	155	216	902	1290
Last Year To This Date	4	57	124	698	883
CONSUMER-HOURS INTERRUPTION					
This Month	1482.25	0	1070.31	6400.70	8,953.26
This Month Last Year	0	0	411.91	2561.82	2,973.73
This Year To Date	24,279.82	30,354.04	8,527.22	54,799.55	117,960.63
Last Year To This Date	13,584.66	5,368.91	4,090.02	28,608.13	51,651.72
AVERAGE HOURS PER CONSUMER					
This Month	.0877	0	.0633	.3788	.5298
This Month Last Year	0	0	.0245	.1527	.1772
This Year To Date	1.4425	1.8112	.5072	3.2619	7.0228
Last Year To This Date	.8215	.3254	.2456	1.7234	3.1159

DATA FOR COMPUTING AVERAGE HOURS PER CONSUMER

Number of Consumers Served This Month: 16,898

Average Number of Consumers This Year To Date: 201,518/12= 16,793

Licking Valley Rural Electric Cooperative Corporation
Response
Item 30

30.

Licking Valley Rural Electric Cooperative Corporation
Commission Reportable Distribution Outages for the Requested Time Period

Cause	Number of Events
Major Storm	**1**
Public	**4**

Licking Valley Rural Electric Cooperative Corporation
Response
Item 31

31. Does your utility have a distribution and / or transmission reliability improvement program?

Licking Valley Rural Electric Cooperative Corporation does not own or control transmission facilities. We do have a distribution reliability improvement program. Our distribution reliability program is managed via outage reports, line inspection reports, maintenance reports and consumer complaints. Areas of concern are reported to management which then takes the appropriate action for response to the situation. It is our opinion that these reports which are prepared by our cooperative employees are principal indicators of our distribution reliability and the efficiency of this program. We have enclosed for your convenience copies of Licking Valley Rural Electric Cooperative Corporation's Current Work Plan and the Long Range Plan.

NEW MEMBER EXTENSIONS – RUS CODE 100

A total of 2,600 new services are anticipated. The projected cost is $3,185,000.
The average length of service per customer is 115 feet. The total projected length for the work plan period is 57 miles.
Cost history and projections are shown in Table III-B-1.

SYSTEM IMPROVEMENTS – RUS CODE 300

LINE CONVERSION NARRATIVES

Oakdale Substation

Code 333-2
Estimated Cost: $98,020
Year: 2004

Description of Proposed Construction
Section 566 – Convert 2.6 miles of single-phase 6ACWC to two-phase 1/0 ACSR.

Reason For Proposed Construction
The section is selected for aged conductor replacement. Design Criteria (DC) item 4 is nearly violated.

Results of Proposed Construction
DC item 4 will be met. This line will also be used to feed one new section. The re-feed will relieve excessive single-phase loading on section 570.

Alternative Corrective Plan Investigated
Since this section was chosen for aged conductor replacement and was nearing DC item 4, no alternatives were considered.

Maggard Substation

Code 337-5
Estimated Cost: $128,100
Year: 2003

Description of Proposed Construction
Section 326 – Convert 3.5 miles of single-phase 6ACWC to two-phase 1/0 ACSR.

Reason For Proposed Construction
The section is experiencing single-phase overloading and excessive voltage drop. Design Criteria (DC) items 1 & 4 are being violated.

Results of Proposed Construction
Single-phase overloading and voltage drop problems will be corrected.

Alternative Corrective Plan Investigated
This is a radial line. No backfeed to relieve loading was possible.

SYSTEM IMPROVEMENTS – RUS CODE 300

Campton Substation

Code 340-7

Estimated Cost: $69,000
Year: 2001

Description of Proposed Construction
Section 423 – Convert 2.0 miles of single-phase 6ACWC to two-phase 1/0 ACSR.

Reason For Proposed Construction
The section is experiencing single-phase overloading and excessive voltage drop. Design Criteria (DC) items 1 & 4 are being violated.

Results of Proposed Construction
Single-phase overloading and voltage drop problems will be corrected.

Alternative Corrective Plan Investigated
This is a radial line. No backfeed to relieve loading was possible.

Campton Substation

Code 341-7

Estimated Cost: $48,000
Year: 2004

Description of Proposed Construction
Section 408 – Convert 0.6 mile of three-phase 3/0 ACSR to three-phase Double Circuit 336.4 ACSR.

Reason For Proposed Construction
A southern feed around the City of Campton is desired to complete an entire loop. This area has one of the highest load densities on the system. Reliability needs to be increased.

Results of Proposed Construction
Service reliability will be improved.

Alternative Corrective Plan Investigated
No alternatives were considered for this project.

SYSTEM IMPROVEMENTS – RUS CODE 300

Campton Substation (continued)

Code 342-7
Estimated Cost: $159,975
Year: 2004

Description of Proposed Construction
Sections 363, 9027, OH1008 & 365 – Convert 2.7 miles of single-phase 6ACWC to three-phase 336.4 ACSR.

Reason For Proposed Construction
The aged conductor is producing unreliable service and a southern feed around the City of Campton is desired to complete an entire loop. This area has one of the highest load densities on the system. Reliability needs to be increased.

Results of Proposed Construction
Service reliability will be improved.

Alternative Corrective Plan Investigated
No alternatives were considered for this project.

Zachariah Substation

Code 343-7
Estimated Cost: $23,700
Year: 2004

Description of Proposed Construction
Section 784 – Convert 0.4 mile of three-phase 6ACWC to three-phase 336.4 ACSR.

Reason For Proposed Construction
This section is composed of aged copper. Reliability to a children's home facility and 165 other customers is compromised due to the condition of the conductor.

Results of Proposed Construction
Service reliability will be improved.

Alternative Corrective Plan Investigated
No alternatives were considered for this project.

SYSTEM IMPROVEMENTS – RUS CODE 300

Campton Substation

Code 344-7

Estimated Cost: $58,520
Year: 2003

Description of Proposed Construction
Section 364 – Convert 1.4 miles of single-phase 6ACWC to three-phase 1/0 ACSR.

Reason For Proposed Construction
The aged conductor is producing unreliable service and Design Criteria item 4 is being violated.

Results of Proposed Construction
Service reliability will be improved and single-phase overloading will be relieved.

Alternative Corrective Plan Investigated
This is a radial line. No backfeed to relieve loading was possible.

Campton Substation

Code 345-7

Estimated Cost: $25,620
Year: 2003

Description of Proposed Construction
Section 213 – Convert 0.7 mile of single-phase 6ACWC to two-phase 1/0 ACSR.

Reason For Proposed Construction
The section is experiencing excessive voltage drop. Design Criteria (DC) item 1 is being violated.

Results of Proposed Construction
Voltage drop problems will be corrected.

Alternative Corrective Plan Investigated
Voltage regulators were considered, but DC item 4 was within 9 amps of violation.

SYSTEM IMPROVEMENTS – RUS CODE 300

Campton Substation (continued)

Code 348-7
Estimated Cost: $26,390
Year: 2004

Description of Proposed Construction
Section 437 – Convert 0.7 mile of single-phase 6ACWC to two-phase 1/0 ACSR.

Reason For Proposed Construction
The section is experiencing single-phase overloading. Design Criteria (DC) item 4 is being violated.

Results of Proposed Construction
Single-phase overloading will be corrected.

Alternative Corrective Plan Investigated
A partial backfeed to relieve single-phase loading on section 437 was made from section 421. This backfeed did not relieve enough load to prevent the DC item 4 violation.

Index Substation

Code 350-8 Carryover
Estimated Cost: $162,000
Year: 2002

Description of Proposed Construction
Section 232 – Convert 4.0 miles of single-phase 6ACWC to three-phase 1/0 ACSR.

Reason For Proposed Construction
The section is experiencing excessive voltage drop. Design Criteria (DC) item 1 is being violated.

Results of Proposed Construction
Voltage drop problems will be corrected.

Alternative Corrective Plan Investigated
Voltage regulators were considered, but DC item 4 was within 8 amps of violation.

SYSTEM IMPROVEMENTS – RUS CODE 300

Maytown Substation

Code 328-9 In Progress

Estimated Cost: $94,560
Year: 2001

Description of Proposed Construction
Sections 33 & 34 – Convert 2.4 miles of single-phase 6ACWC to three-phase 1/0 ACSR.

Reason For Proposed Construction
The sections are experiencing single-phase overloading. Design Criteria (DC) item 4 is being violated.

Results of Proposed Construction
Single-phase overloading will be corrected.

Alternative Corrective Plan Investigated
These are radial lines. No backfeed to relieve loading was possible.

LICKING VALLEY RECC 2001-2005 CWP

AGED CONDUCTOR REPLACEMENT - RUS CODE 300

SUB - SECTION	RUS CODE	INST. COND/#-PH	$/MILES	# OF MILES	2001	2002	2003	2004	TOTAL
Maytown - 32 & 34	328-9	1/0 ACSR -1 Phase	$25,000	4.0	$100,000				$100,000
Oakdale - 572 & 573	330-2	1/0 ACSR -1 Phase	$25,500	6.6		$168,300			$168,300
Oakdale - 650-652	331-2	1/0 ACSR -1 Phase	$25,000	9.5	$237,500				$237,500
Oakdale - 567 & 570	332-2	1/0 ACSR -1 Phase	$25,500	7.0		$178,500			$178,500
Oakdale - 645	334-2	#2 ACSR -1 Phase	$23,500	2.5				$58,750	$58,750
Helechewa - 240 & 426	336-3	1/0 ACSR -1 Phase	$25,000	5.2	$130,000				$130,000
Sublett - 557 & 560	338-6	1/0 ACSR -1 Phase	$25,500	4.4		$112,200			$112,200
Sublett - 643 & 644	339-6	1/0 ACSR -1 Phase	$26,000	4.6			$119,600		$119,600
Campton - 367, 384 & 409	346-7	1/0 ACSR -1 Phase	$26,000	3.0			$78,000		$78,000
Campton - 366,383 & OH1007	347-7	#2 ACSR -1 Phase	$23,000	10.0			$230,000		$230,000
Maytown - 204-206	351-9	1/0 ACSR -1 Phase	$25,000	5.2	$130,000				$130,000
Maytown - 203	352-9	#2 ACSR -1 Phase	$21,500	1.3	$27,950				$27,950
		TOTAL:		63.3	$625,450	$459,000	$427,600	$58,750	$1,570,800

CARRYOVER ITEMS

MISCELLANEOUS DISTRIBUTION EQUIPMENT – RUS CODE 600's

Meters and Transformers – RUS Code 601
1,742 new transformers are projected at a cost of $1,241,175.
2,600 new meters are projected at a cost of $246,000.
Historical data for meters and transformers is included in Table III-B-1.

An **Automated Meter Reading (AMR)** Pilot Program using "LINK" meters is proposed. The computer equipment was purchased previously and 400 LINK meters will be installed during the CWP period. The cost per meter is $120 and the net overall cost of meters can be seen in Table III-B-1.

The first objective of the AMR program is to install a unit past each oil circuit recloser or major tap fuse. Such a placement of these devices will provide a cost-effective monitoring system that greatly improves outage management.

There are isolated locations where it is more cost effective to install AMR than to have a person physically read a meter on a monthly basis. Selected large power loads (over 25 kW) are being evaluated for the AMR program since all of these meters are presently being physically read each month. There are also several "locked-gate" situations that are candidates for the AMR program.

Additional benefits include the monitoring of end-of-line voltage and possible system disturbances or customer-related voltage problems. This data is useful for comparing real-time voltage to the computerized voltage drop models. With the improved data, the timing and scale of major system improvements can be better managed - resulting in deferred capital costs while maintaining quality service.

LVRECC plans to extend the program during the next construction work plan period. Additional benefits will include improved revenue flow, transformer sizing, transformer loss evaluation, rate design, detailed billing downloads into engineering analysis software and the elimination of energy diversion.

Service Upgrades – RUS Code 602
There are 620 service upgrades projected at a total cost of $421,600. Historical data is included in Table III-B-1.

Sectionalizing – RUS Code 603

Overcurrent analysis is performed on an ongoing basis. Device changeouts, conductor multiphasing and load shifts require overcurrent device purchases.

Oil circuit reclosers, fuses and switches are included in this category. $70,000 for each of the four years has been allocated. In addition, two overhead air break switches ($10,000) are recommended for the Campton Loop project. The total projected cost for sectionalizing is $290,000.

Voltage Regulators – RUS Code 604

Two sets of voltage regulator additions are projected for the CWP as follows:

CFR CODE	SUBSTATION	SECT/RATING	YEAR	COST
604-4A	WEST LIBERTY	30/ (3) 100 A	2001	$30,000
604-8A	INDEX	74/ (3) 50 A	2004	$22,200

Capacitor Banks – RUS Code 605

Four capacitor banks are projected in the CWP

CFR CODE	SUBSTATION	SECT/RATING	YEAR	COST
605-1A	ZACHARIAH	344/SWITCH	2002	$2,163
605-4A	WEST LIBERTY	3/SWITCH	2001	$2,200
605-4B	WEST LIBERTY	2/300 KVAR	2004	$2,295
605-8A	INDEX	82/SWITCH	2002	$2,266

Pole Changes – RUS Code 606 Including Clearance Poles

There are 500 projected pole changes in the CWP. This includes all maintenance and clearance poles. The cost for the pole changes is projected to be $507,500. Historical cost data for pole changes may be found in Table III-B-1.

RUS CODE 700

Security Lights – RUS Code 701
A total of 1,500 new security lights are anticipated. The projected cost is $450,000. Security light cost history and projections are shown in Table III-B-1.

II. GENERAL DESCRIPTION OF THE REPORT

A. Summary

During the process of selecting a Recommended Long Range Plan, two designs were developed and evaluated. One plan arbitrarily named Plan A, proposed the continued development of the existing 7.2/12.5 kV distribution system, and the other, Plan B, proposed the conversion of all the existing primary distribution facilities to 14.4/24.9 kV. For both plans, the transition from the existing system to the proposed long range configuration was developed in detail. The transition plans include a detailed analysis of system performance and cost at intermediate levels between the existing system load and the projected long range load. The two plans were compared on the criteria discussed in this report and Plan A - 12.5 kV was selected as the Recommended Plan. The following table summarizes the cost comparison of the two plans.

A detailed description of the Recommended Long Range Plan is included herein accompanied by itemized cost estimates for each load level. A description of the Alternate Long Range Plan is also included, as well as cost estimates and the economic comparisons for the two plans.

The Appendices contain supporting data and calculations used to develop the two designs.

The circuit diagrams prepared in conjunction with this study represent the Recommended Plan at the long-range load level.

B. Economic Comparison of Plans

	Distribution System Improvements	Transmission & Substation Improvements	Member Service Extensions	Distribution Line Losses	TOTAL
RECOMMENDED PLAN (12 kV Distribution)					
Load Block A	$ 4,496,400	$ 1,427,300	$ 5,581,477	$ 851,770	$ 12,356,947
Load Block B	$ 6,078,300	$ 599,150	$ 5,610,949	$ 1,342,902	$ 13,631,301
Load Block C	$ 12,958,800	$ 5,537,900	$ 11,100,499	$ 2,131,544	$ 31,728,743
Total	$ 23,533,500	$ 7,564,350	$ 22,292,925	$ 4,326,216	$ 57,716,991
Present Worth					$ 47,612,752
ALTERNATE PLAN (25 kV Distribution)					
Load Block A	$ 8,495,750	$ 1,628,975	$ 5,581,477	$ 640,293	$ 16,346,495
Load Block B	$ 9,992,750	$ 1,945,800	$ 5,610,949	$ 995,028	$ 18,544,527
Load Block C	$ 14,947,625	$ 1,410,475	$ 11,100,499	$ 1,569,777	$ 29,028,376
Total	$ 33,436,125	$ 4,985,250	$ 22,292,925	$ 3,205,098	$ 63,919,398
Present Worth					$ 57,957,893

C. Recommendations

It is the recommendation of this report that the Licking Valley RECC system additions and changes included in future Work Plans be in accordance with the Recommended Long Range Plan developed in this report. This report should be reviewed in conjunction with the preparation of Construction Work Plans and revised as necessary to reflect changing conditions.

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

SUMMARY OF SYSTEM PLANNING REPORT

INSTRUCTIONS - *See reverse side.*

SYSTEM DESIGNATION	REA FIELD ENGINEER
KENTUCKY 56 MORGAN	M. NORMAN
DATE PLANNING REPORT COMPLETED	**PLANNING ENGINEER**
MARCH 1, 1998	KEVIN MARA

PART I GENERAL DATA

ITEMS 1.	2. LINE MILES		3. NO. OF CONSUMERS		TOTAL SYSTEM LOAD (kw) 4.	TOTAL SPECIAL LOADS (kw) 5.	TOTAL YEARLY SALES KWH 6.	7. PAST PEAK LOAD		DESIGN LOAD KWH/CONS./MO. PEAK MO. 8.
	TRANS. a.	DISTR. b.	ALL TYPES (Includes special loads) a.	SPECIAL LOADS b.				KWH/CONS./MO. a.	DATE b.	
PRESENT SYSTEM AS OF	N/A	1885	14894	0	60,665	0	214,372,320	1595	1/94	
LONG RANGE PLAN	17*	2123	19573	0	107,500	0	414,348,000			1695

PART II LINE MILES

ITEMS 1.	DISTRIBUTION			TRANSMISSION		
	7.2/12.5 KV 2.	14.4/24.9 KV 3.	____ KV 4.	34.5 KV 5.	69 KV 6.	____ KV 7.
PRESENT SYSTEM AS OF	1885				N/A	
LONG RANGE PLAN	2123				17*	

PART III SUBSTATIONS AND METERING POINTS

NAME OR LOCATION* 1.	POWER SUPPLIER 2.	3. PRESENT SYSTEM			4. LONG RANGE PLAN		
		KVA a.	KV PRIMARY b.	KV SECONDARY c.	KVA a.	KV PRIMARY b.	KV SECONDARY c.
ZACHARIAH	EKP	3750	69	12.5	10,000	69	12.5
OAKDALE	EKP	5000	69	12.5	10,000	69	12.5
HELECHEWA	EKP	11,200	69	12.5	11,200	69	12.5
WEST LIBERTY	EKP	6,500	69	12.5	10,000	69	12.5
MAGGARD	EKP	5,000	69	12.5	10,000	69	12.5
SUBLETT	EKP	11,200	69	12.5	11,200	69	12.5
CAMPTON	EKP	10,000	69	12.5	12,000	69	12.5
INDEX	EKP	10,000	69	12.5	12,000	69	12.5
MAYTOWN	EKP	11,200	69	12.5	11,200	69	12.5
CROCKETT	EKP	11,200	69	12.5	11,200	69	12.5
VANCLEVE	EKP				10,000	69	12.5
CANNEL CITY	EKP				10,000	69	12.5
EZEL	EKP				10,000	69	12.5
LONG BRANCH	EKP				10,000	69	12.5
BEAR BRANCH	EKP				10,000	69	12.5

PART IV INVESTMENT IN PLANT (Dollars)

ITEMS 1.	TRANSMISSION LINES 2.	ALL SUBSTATIONS 3.	DISTRIBUTION TRANSFORMERS, METERS & SERVICES 4.	ALL OTHER DISTRIBUTION FACILITIES 5.	TOTAL T & D PLANT 6	GENERAL & PROD. PLANT 7
PRESENT SYSTEM AS OF	0	$31,442	$8,624,257	$18,985,921	$27,641,620	$30,281,347
LONG RANGE PLAN	$2,785,000*	$4,779,350*	$11,721,665	$34,104,759	$53,390,774	

NOTED

DATE	SIGNATURE	DATE	SIGNATURE
	CHIEF, AREA ENGINEERING BRANCH		AREA DIRECTOR

*Include those furnished by Power Supplier and designate with asterisk.

REA FORM 261 REV. 1-62

Licking Valley Rural Electric Cooperative Corporation
Response
Item 32

32. Provide a summary description of your utilities:

a. Right of Way management program. Provide the budget for the last five (5) years.
b. Vegetation management program. Provide the budget for the last five (5) years.
c. Transmission and Distribution inspection program. Provide the budget for the last five (5) years.

32a

Licking Valley Rural Electric Cooperative Corporation Right of Way Clearing Cost For The Requested Time Period

Year	Licking Valley RECC Cost Right of Way Clearing	Contractor Cost Right of Way Clearing	Total
2000	$26,587	$403,089 (Bartlett)	$429,676
2001	$ 1,553	$58,270 (Bartlett) $420,267 (WA Kendall)	$480,090
2002	$6,662	$517,101 (WA Kendall)	$523,763
2003	$8,648	$406,664 (WA Kendall)	$415,312
2004	$16,490	$367,380 (WA Kendall)	$383,870

32b

Vegetation Control: Licking Valley Rural Electric Cooperative Corporation has an aggressive right of way program and has contracted WA Kendall to address our cooperatives right of way requirements. Our cooperative likes to maintain sixty - foot of right of way clearance on new and existing accounts. There are a total of five crews working on right of way; however one right of way crew will concentrate on Herbicide Treatment, principally from the months of May until August or September.

32c
Licking Valley Rural Electric Cooperative Corporation's Transmission and Distribution Line Inspection Program budget for the past five (5) years.

Year	Expense
2000	$328.85
2001	0
2002	$42,452.44
2003	$25,619.19
2004	$42,000.00

Licking Valley Rural Electric Cooperative Corporation has established an assertive line and pole inspection program. All service personnel for Licking Valley RECC, which includes maintenance and construction crew members, in addition to engineering, metering personnel, plus right of way contractors and construction contractors are very knowledgeable and perform a visual inspection of its distribution lines on a regular basis when they are at sites.

Licking Valley RECC takes active measures to ensure that deficiencies found are reported and corrected in a timely manner.

In 2004 Licking Valley RECC had personnel who performed line inspection via a helicopter. There was 100% of Licking Valley RECC territory which was checked for inadequacy. When this crew found a problem pertaining to any of our distribution lines, prompt action was taken to resolve this situation.

Licking Valley Rural Electric Cooperative Corporation
Response
Item 33

33. Explain the criteria your utility uses to determine if pole or conductor replacement is necessary. Provide costs/budgets for transmission and distribution facilities replacement for the years 2000 through 2025.

Licking Valley Rural Electric Cooperative Corporation does not own or control transmission facilities.

Licking Valley RECC does routinely inspect the physical condition of its distribution poles and lines. Poles go through a visual inspection on a two (2) year cycle. Licking Valley RECC depends essentially on their operating personnel to identify structures that should be considered for pole replacement. Please find insert, relating to the Criteria for Long Range System Planning.

III. CRITERIA FOR LONG RANGE SYSTEM PLANNING

A. Load Levels

The long range load criteria was established with the assistance of Licking Valley RECC's staff. It was decided to design the system to support a long range peak demand of approximately 1.8 times the February, 1996 non-coincident demand. This demand level is consistent with Licking Valley RECC's 1996 Power Requirements Study. Graphs of the total system kW demand and each substation kW demand are included in Appendix A.

Three load levels were used which correspond to the loads projected for the years 2001, 2006 and 2016. The following is a summary of the criteria for the System Planning Report Load Levels:

	Existing System (MW)	Load Block A (MW)	Load Block B (MW)	Load Block C (MW)
Zachariah	2.4	3.1	3.6	4.5
Oakdale	6.8	6.8	7.8	11.0
Helechawa	8.2	8.5	10.0	14.0
West Liberty	4.0	5.4	6.3	8.0
Maggard	5.5	5.4	6.1	8.1
Sublett	9.0	10.0	11.0	14.5
Campton	8.9	9.3	11.0	15.6
Index	9.0	11.0	13.0	18.8
Maytown	3.6	4.2	4.8	6.1
Crockett	3.3	5.2	5.6	6.9
Total System	**60.7**	**68.9**	**79.2**	**107.5**

B. Voltage Drops

The following criteria was used in determining the permissible voltage drops throughout the design phase of this study:

Maximum Allowable Voltage Drops

16 volts with line regulators
8 volts without line regulators

The load and voltage calculations for each load level were based on the assumption of a balanced load in all multi-phase line sections of the computer model. In the final Load Block (Load Block C) the maximum allowable voltage drop will be 8.0 volts with no line regulators.

C. Single Contingency Outage

The system should be designed so that a single contingency outage can be safely isolated and the rest of the system may continue to operate based on the emergency ratings of the system components affected by the outage. This is essential, not only for maintaining high levels of reliability, but also to allow for the maintenance of specific devices and lines on the electric system. This criterion is not a hard and fast one but is a good goal for the distribution system.

D. Capacity of System Components

The overhead conductors on the distribution system will be assigned capacity levels, for both winter and summer, known as normal rating and emergency rating respectively. Any line which is required to carry more than its normal capacity shall be reviewed in the field to verify its ability to carry the increase in load and still maintain the safety requirements as established by the latest revision of the NESC during maximum sag conditions. The ratings will be based on the following guidelines:

	Normal		Emergency	
	Summer	Winter	Summer	Winter
Ambient Temp.	36	-10	36	-10
Conductor Temp	50	50	75	75
6A	65	156	119	180
4ACSR	65	157	118	179
2ACSR	85	207	155	235
1/0ACSR	109	273	204	310
3/0ACSR	140	358	264	403
336ACSR	212	570	436	669

The normal rating shall not be exceeded for use in planning the system during normal operating conditions. The emergency rating shall be used in planning for single contingency outages. Further, it is also assumed that all accessories (jumpers, splices, etc.) shall be rated equal to or greater than the ampacities listed for the emergency ratings.

All underground shall not be loaded beyond the normal loading recommendations of the cable manufacturers. These recommendations should take into account the installation method used, i.e., direct buried, conduit, riser pole.

IV. EXISTING SYSTEM ANALYSIS

A. General Discussion

The purpose of this analysis is to examine the Licking Valley RECC's existing distribution system facilities in terms of their overall capability to provide acceptable standards of service at both existing and projected long range load levels. The principal objective of this analysis is to provide a broad and very general definition of the existing system that can then be used as a basis for the various system designs developed for the System Planning Report.

The following procedure was used in making the Existing System Analysis:

1. System Model - A distribution system computer model was used to reflect the Cooperative's existing system configuration and the most recent peak month loading, which was February, 1996.
2. Load Projections - Twenty year projections of consumers, usage, and kW demand were made for the overall system. These projections were coordinated with those made in conjunction with the Cooperative's 1996 Power Requirements Study.
3. Load and Voltage Analysis - Separate computer runs were made to calculate the load and voltage levels at each line section for the existing system with the projected long range (twenty year) load.

B. Service Area

The Licking Valley Rural Electric Cooperative Corporation, with headquarters in West Liberty, Kentucky supplies electric service to its rural consumers in Breathitt, Magoffin, Morgan and Wolfe counties. Service is provided to approximately 14,862 consumers who have an average consumption of about 1,196 kilowatt hours per month.

Wholesale power purchases are made from East Kentucky Power. The distribution substations are owned, operated and maintained by East Kentucky Power.

C. Load Growth Characteristics

Accurate projections of the system loads into the future are critical when preparing a Long Range Plan. The 1996 Power Requirements Study was an excellent source for projecting total system demand, the total number of consumers and average usage.

Graphs were prepared (Appendix A) of the non-coincident peak demand of all the substations. Using the trends seen from the historical demand of each substation, the 4 year, 10 year and 20 year projections were made such that their sum was close to that of the 1996 Power Requirements Study.

Licking Valley's staff and Southern Engineering Company then determined areas where spot loads may locate. A spot load for this study is defined as a concentrated area of

commercial development or a residential subdivision. A list of these loads and their general location can be found on page 16 of Appendix A.

The final projections are within the "extreme weather" prediction of the PRS.

D. Service Reliability

The Cooperative's system outage data for the last five years is summarized in the following table. A primary objective of the Long Range Plan is the consideration of the reliability implications associated with major system configuration changes. Alternate plans should be evaluated in terms of reliability as well as economic factors.

Consumer Hours of Outage Per Year

Year	Source	Storm	Prearranged	Other	Total
1993	1.444	3.711	0.193	1.101	6.449
1994	11.404	25.870	0.260	1.834	39.368
1995	1.169	1.319	0.502	1.705	4.695
1996	0.450	1.130	1.440	2.810	5.830
1997	0.450	1.136	1.444	2.812	5.842
Average	2.983	6.633	0.768	2.052	12.437

The average of consumer outage hours is reduced to 5.7 if 1994 data is excluded. The goal of the cooperative should be to reduce this value below 5.0. This study recommends conductor and pole replacements to reduce the number of consumer outages. In addition, the cooperative should consider reducing the amount of pre-arranged outages.

E. System Power Factor

The Cooperative uses a combination of fixed and switched capacitor banks to help reduce line losses and improve the voltage profile of its distribution system. It is recommended that the Cooperative monitor the system power factor and make whatever adjustments are necessary to maintain their power factor above 95% whenever possible.

F. System Losses

1. System Losses

The Cooperative's system energy losses for the past five years are shown on the following table. RUS suggests that the losses for a system based on 106,000 kWh billed per mile of line should be 8.5%. In view of increasing wholesale power costs, it is important that the Cooperative continue its efforts to reduce losses when it is economically feasible to do so. Economic consideration should be included in the selection of distribution transformers and primary distribution system conductors.

Year	kWh Purchased	kWh Sold	kWh Lost	% Losses	Miles of Line	kWh Billed per Mile of Line
1993	203,741,731	188,379,667	15,362,064	7.5%	1,856	101,498
1994	203,885,338	189,739,713	14,145,625	6.9%	1,858	102,120
1995	218,274,854	201,439,880	16,834,974	7.7%	1,866	107,953
1996	225,849,685	213,247,208	12,602,477	5.6%	1,876	113,671
1997	226,109,913	214,372,320	11,737,593	5.2%	1,885	113,725
Average	215,572,304	201,435,758	14,136,547	6.6%	1,868	107,793

2. Economic Conductor Size

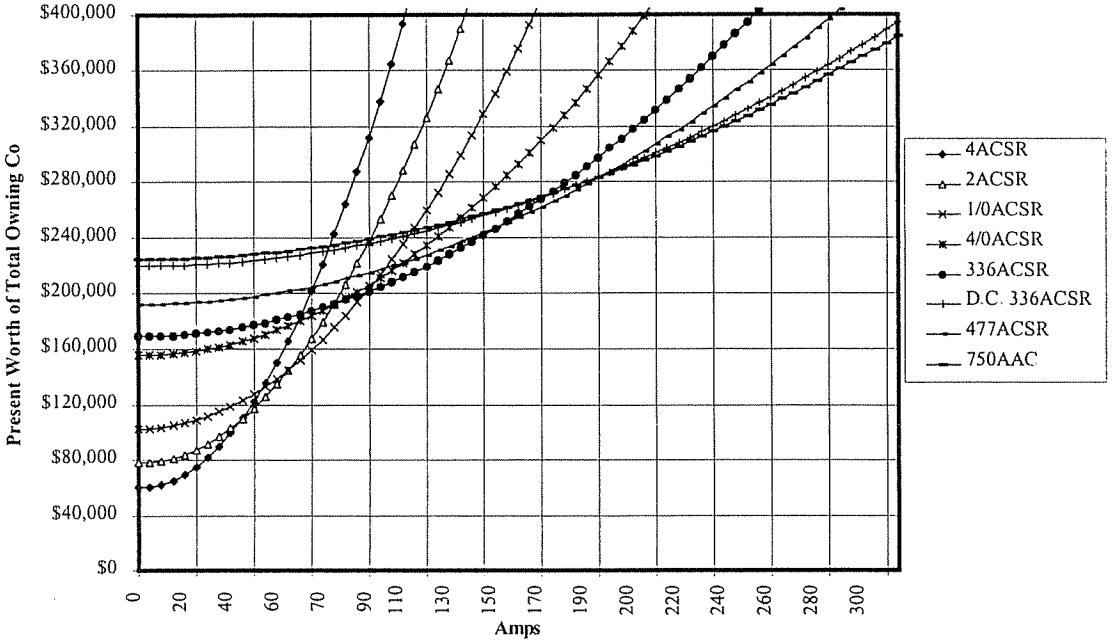
One of the objectives of the System Planning Report is to make recommendations as to the economical sizes and types of conductor to be used on the Cooperative's system and to establish a procedure for a periodic review of economic conductor selection. This procedure should include current economic considerations such as power cost inflation rates, load growth rates, changes in interest rates, and changes in construction costs.

The following two graphs show the results of the economic conductor analysis for three phase and single phase lines.

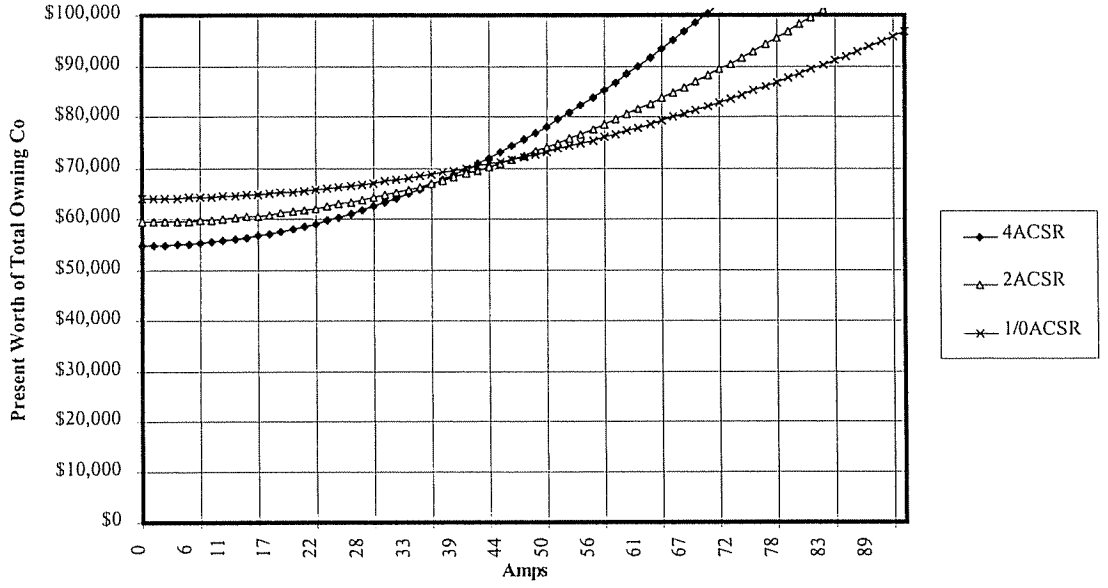
For initial loads of more than 100 amps the recommended conductor is 336ACSR. Double circuit 336ACSR is recommended for loads above 195 amps. The data indicates that 750AAC would be more economical however this would reduce the reliability of the system. For the next wire size, 1/0ACSR is recommended for load of 65-100 amps. For load below 65 amps, 2ACSR is recommended. The graph shows that 4ACSR is more economical for load below 40 amps however, 2ACSR is better suited for the physical conditions of the region in that it is strong and can withstand more mechanical stress.

For single phase conductor, 2ACSR is recommended for radial single phase lines. The 2ACSR is preferred over the more economical 4ACSR because the 2ACSR has greater mechanical strength. This makes the 2ACSR more reliable in wind and ice storms. For single phase tie lines and heavily loaded single phase taps, 1/0ACSR is recommended. The larger conductor allows for future growth and is easier to multi-phase in the future.

ECONOMIC CONDUCTOR SIZE
FOR THREE PHASE LINES
KY56 LICKING VALLEY



ECONOMIC CONDUCTOR SIZE
FOR SINGLE PHASE LINES
KY56 LICKING VALLEY



G. Copper Replacement

According to data taken from the Continuing Property Records and discussions with the engineering staff, the Cooperative has approximately 560 miles of copper in service on their system. The Recommended Plan calls for the replacement of about 160 miles of copper from planned system upgrades to solve low voltage problems or ampacity problems or both. It is recommended that the Cooperative replace the remaining 400 miles at a rate of 20 miles per year over the 20 year planning period. Copper replacement is included in the System Wide cost estimates.

F. Financial

The fixed charge cost for the Cooperative was calculated for the purpose of comparing options in terms of present worth. Page twenty two of the Appendix A shows the calculation used in the analysis.

V. Long Range Plans

A. Recommended Long Range Plan

The Recommended Long Range Plan proposes 5 new substations for a total of 14 substations for the Recommended Long Range Plan. In addition to the new substations, five of the existing substations will require the capacity to be increased by the end of the Long Range Planning period. The recommended plan proposes that the entire system remain at 7.2/12.5 kV.

Line changes and increasing conductor size and/or the number of phases for approximately 218.4 miles of primary distribution line and the construction of approximately 3.6 miles of new primary distribution line are recommended in this plan. Some of these improvements will be required in order to maintain adequate voltage levels throughout the system and others are recommended in order to provide sufficient line capacity or to improve system reliability. Further, others are required to provide system redundancy to comply with the planning criteria of a single contingency outage on the distribution system.

Transmission planning is beyond the scope of this report. However, transmission costs are included in this study for the comparison of the Recommended and Alternate Plans.

The plan was developed using three planning periods, Load Blocks A, B, and C which correlate into the years 2001, 2006 and 2016 respectively. The following pages contain a more detailed discussion of the major distribution improvements. The discussion is divided into three periods of the load growth or load levels.

Several Exploratory plans were investigated and compared in terms of present worth to the Recommended Plan. A detailed discussion of these exploratory plans can be found in Section V-D.

1. Load Block A - Improvements shown in Red on the Circuit Diagram

The nominal total non-coincident system peak demand for Load Block A is 68.9 MW. It is estimated that the system will be serving 16,084 consumers at a peak month average of 1,537 kWh per consumer.

In this load block, two stations, Maggard and Oakdale require an increase in their power transformer capacity. The need for the increase is related directly to the load growth that is occurring on the system. Approximately, 6.1 miles of line on the Gunlock Circuit out of Sublett Substation is to be converted to 336ACSR. This line helps to delay the need for the Proposed Long Branch Substation. Exploratory Plan 1 investigated the option of constructing the County Line Substation (at the end of line section 643) rather than constructing the Proposed Long Branch Substation. In addition, Exploratory Plan 2

considered constructing the Long Branch Substation in Load Block A and eliminating the reconductoring of 6.1 miles of line. Both of these exploratory plans cost more in terms of present worth than the Recommended Plan. However, the County Line Substation maybe prove to be desirable if the station can be shared by Licking Valley RECC and Big Sandy RECC. Presently, Big Sandy RECC does not require the County Line Substation but if a mining load locates in this area, then the location of the proposed station should be reconsidered.

The Proposed Bear Branch Substation is located roughly west of the Sublett Substation. This station is located adjacent to the existing transmission line that feeds the Sublett Substation so there is very little cost associated with the transmission extension to this proposed station. This station is also needed to meet the voltage level requirements in the planning criteria. It also eliminates the need to reconductor 9.3 miles of 3/0ACSR to 336ACSR on Sublett, Circuit 2 and delays the need to reconductor 4.3 miles of single phase 6A on Circuit 1 until Load Block C. An alternate site was considered by Exploratory Plan 4. This exploratory plan suggested that station be located west of the Bear Branch site and referred to as the Proposed Seitz Substation. The Bear Branch location is more in the load center and needed less system improvements and was less expensive in terms of present worth. Exploratory plans 6 and 7 call for the reconductoring of 4.3 miles of single phase line to delay the need for the new station however these plans were more costly in terms of present worth.

2. Load Block B - Improvements shown in Blue on the Circuit Diagram

The nominal total non-coincident system peak demand for Load Block B is 79.2 MW. It is estimated that the system will be serving 17,266 consumers at a peak month average of 1,577 kWh per consumer.

In this load block, the Index and West Liberty Substation will require an increase in their power transformer capacity. A new circuit is proposed out of the Campton Substation. One of the biggest distribution projects in this lock block is the conversion work proposed out of the Crockett Substation. Approximately 6.2 miles of single phase is proposed to be converted to 336ACSR. This conversion is necessary to maintain voltage levels described in the planning criteria. Consideration was given to reconductoring the three phase circuit north of this proposed conversion project. However, the proposed project is less expensive and greatly helps to increase service reliability in this portion of the system. The existing #4 copper line, line sections 122,123, 9011, and 125, that runs east around the City of West Liberty is proposed to be converted to 1/0ACSR in this load block. This project will help to maintain adequate reliability levels as well as achieving a goal of the Cooperative to retire old copper line.

3. Load Block C - Improvements shown in Green on the Circuit Diagram

The nominal total non-coincident system peak demand for Load Block B is 107.5 MW. It is estimated that the system will be serving 19,573 consumers at a peak month average of 1,695 kWh per consumer.

Four new substations are recommended in this load block; Long Branch Substation, Vancleve Substation, Cannel City Substation and Ezel Substation. A capacity increase is also recommended at the Campton Substation and the Zachariah Substation in this load block.

The Long Branch Substation is located roughly south of the Sublett Substation. A transmission tap of 7.5 miles is required to provide service to this station. The projected load at this proposed station is 2.4 MW. The voltage drops at the end of circuit dictate the need for this station. The planning criteria requires no more than an eight volt drop without the use of line regulators. In order to meet this design requirement without a substation, it would be necessary to either double circuit the line out of Sublett Substation or increase the conductor size to the very end of the circuit. Neither of these options are considered reasonable and were not fully developed as an alternative. However, three Exploratory Plans were considered as alternate solutions in this portion of the system. Reference should be made to the description of Exploratory Plans 1, 2 and 3 for more details.

The Vancleve Substation is located roughly equal distance from the Helechewa, Oakdale, and Campton Substations. This station greatly improves the reliability of the system by providing backfeed capabilities to all of these existing stations. A 2.0 mile long transmission tap is required to provide service to this station. In addition, there a number of large distribution projects required to tie this station in the rest of the system. It may be necessary to move this station to an earlier load block based upon system reliability considerations. The long circuits in this portion of the system may require another station to reduce outage times. At this time however, outages are not a major concern.

The Cannel City Substation is proposed to be located roughly south of the Index Substation. This station is expected to service 5.4 MW of load by the end of Load Block C. This station will increase reliability and meet the requirements of the planning criteria. A distribution alternative to this substation was considered but deemed not feasible because of the conductor size necessary to reduce the voltage drops at the end of the affected circuits.

The Ezel Substation is also projected to be constructed in Load Block C. It is located between Maytown and West Liberty Substations. This station is designed to increase reliability and to meet the requirements of the planning criteria. A distribution alternative to this substation was considered but deemed not feasible because of the conductor size necessary to reduce the voltage drops at the end of the affected circuits. In addition, this station eliminates the need to increase the capacity at the Maytown Substation. The proposed site of this station is very close to an existing transmission line so the cost of the transmission tap is a major factor.

B. Alternate Long Range Plan

Circuit diagrams of the Alternate Long Range Plan design were prepared but are not included in this report. The cost estimates by substation are itemized for each of the three load blocks of the Long Range Plan and can be found in Appendix B. The Alternate Plan differs from the Recommended Plan in that the Alternate Plan proposes that the system be converted to 14.4/24.9 kV operation by the last load block.

In the Alternate Plan, no new substations are recommended. In the first load block, Sublett Substation and Helechewa Substation, Circuit 3 will need to be converted to 25 kV operation. In Load Block B, Oakdale, Campton and Crockett Substations would be required. In Load Block C, the remaining portions of the system would be converted to 25 kV operations.

Conversion to 25 kV would make better use of the existing conductor size and also would require no new substations and therefore no transmission expenditures as in the Recommended Plan.

C. Discussion of Plan Selection

In selecting the recommended plan, the following factors were considered.

1. Economic Analysis

As demonstrated by the economic comparison of the plans of Page 3, entitled "Economic Comparison of the Plans", the present worth investment of the Recommended Plan (12 kV) is 18% lower than the Alternate Plan (25 kV). Economic comparison of the exploratory plans concluded that the most economic option is contained in the Recommend Plan.

2. System Capacity

The Recommended Plan has more total station capacity than the Alternate Plan, primarily because of the number of new stations. In addition, there are more tie lines between stations.

3. Service Reliability

The 12 kV plan is considered more reliable because of the shorter circuits and the flexibility that it gives for providing backfeed to different substations and different circuits. In addition, the loss of a single system component affects fewer consumers in the 12 kV plan that the 25 kV plan.

4. Ease of Transition to 25 kV

The Recommended Plan requires no transition of voltage, whereas the Alternate Plan would include the cumbersome task of converting different areas of the existing system while leaving adjacent portions at 12 kV.

5. Use of Existing Facilities

The Recommended Plan makes better use of the existing distribution facilities and does not require the re-insulation of all of the distribution line and replacement of existing distribution transformers. However, the Alternate Plan makes better use of the existing substation sites and the existing conductor.

In summary, the Recommended Plan costs less than the Alternate Plan in terms of present worth by 18%. Also, in consideration of the system as a whole, the Recommended plan is favored over the Alternate Plan in all other categories presented above, including station and line capacity, operational consideration, service reliability, ease of transition and the use of existing facilities. Also, the Recommended Plan will provide additional capabilities to respond to new load and unforeseen changes in growth patterns.

D. Exploratory Plans

1. County Line Substation – This plan constructs County Line Substation in Load Block C. This plan would be more economically feasible if the substation and transmission costs were shared with Big Sandy RECC. However, Big Sandy does not require this substation at this time.

2. Long Branch Substation in Load Block A – This plan constructs Long Branch Substation in Load Block A. This plan eliminates the need to reconductor 6.1 miles of line to 336ACSR. This plan however was more costly in terms of present worth than the recommended plan that calls for the reconductoring of the line to delay the substation until Load Block C.

3. Long Branch Substation in Load Block C - This plan reconductors 6.1 miles of line to 336ACSR to delay the need for the Long Branch Substation until Load Block C. This plan is included as part of the Recommended Plan.

4. Seitz Substation in Load Block A – This substation site is west of the Proposed Bear Branch Substation site location in the recommended plan. A substation is necessary to meet the voltage level requirements in the planning criteria. It also eliminates the need to reconductor 9.3 miles of 3/0ACSR to 336ACSR. The economic analysis of this site proved to be more costly than the recommended plan due to the necessary distribution improvements involved.

5. Bear Branch Substation in Load Block A - This substation is located west of the Sublett Substation. This substation is necessary to meet the voltage level requirements in the planning criteria. It also eliminates the need to reconductor 9.3 miles of 3/0ACSR to 336ACSR. This exploratory plan is included in the Recommended Plan.

6. Seitz Substation in Load Block C - This exploratory plan called for the reconductoring of 4.3 miles of single phase 6A to three phase 336ACSR in order to delay the Seitz Substation. This reconductoring project has been recommended in the two previous Work Plans but has not been completed due to right-of-way problems. This plan was more costly in terms of present worth than the Recommended Plan.

7. Bear Branch Substation in Load Block C - This exploratory plan called for the reconductoring of 4.3 miles of single phase 6A to three phase 336ACSR in order to delay the proposed Bear Branch Substation. This reconductoring project has been recommended in the two previous Work Plans but has not been completed due to right-of-way problems. This plan was more costly in terms of present worth than the Recommended Plan.

Plan Description		
		20 Year Present Worth
Plan 1	County Line Substation in Load Block C	$48,146,584
Plan 2	Long Beach Substation in Load Block A	$48,136,795
Plan 3	Long Beach Substation in Load Block C	$47,716,486*
Plan 4	Seitz Substation in Load Block A	$47,868,262
Plan 5	Bear Branch in Load Block A	$47,612,752*
Plan 6	Seitz Substation in Load Block C	$48,297,457
Plan 7	Bear Branch in Load Block C	$48,176,243

*Plan is included in the Recommended Plan.

Plans 1 – 3 compare options to serve the projected load south of the Sublett Substation.

Plans 4 – 7 compare options to serve the projected load west of the Sublett Substation.

Details of the cost estimate of these exploratory plans can be found in Appendix D.

VI. RECOMMENDED LONG RANGE PLAN COST ESTIMATES

A. Member Service Extensions

The following pages provide the estimated cost of the Member Service Extensions for the Recommended Plan. The calculation of the present worth of these estimates can be found in Section VI - D along with the estimated cost of line losses.

KENTUCKY 56 MORGAN
LONG RANGE PLAN
MEMBER SERVICE COST ESTIMATES

		Historical 24 Months Ending 8/95	Projected Load Block A	Projected Load Block B	Projected Load Block C	Total
1	Number of New Services					
2	Overhead	1,282	2,880	2,900	5,640	11,420
3	Underground	16	100	100	200	400
4	Total	1,298	2,980	3,000	5,840	11,820
5	Historical Total Feet of Line					
6	Primary Line					
7	Overhead	131,772	296,024	298,080	579,714	1,173,818
8	Underground	2,519	15,744	15,744	31,488	62,976
9	Secondary and Services					
10	Overhead	149,357	335,529	337,859	657,078	1,330,467
11	Underground	1,871	11,694	11,694	23,387	46,774
12	Total Feet of Line					
13	Overhead	281,129	631,553	635,939	1,236,792	2,504,285
14	Underground	4,390	27,438	27,438	54,875	109,750
15	Average Length of Service in Feet					
16	Overhead	219	219	219	219	
17	Underground	274	274	274	274	
18	Miles of Line					
19	Overhead	53.2	119.6	120.4	234.2	474
20	Underground	0.8	5.2	5.2	10.4	21
21	Total	54.0	124.8	125.6	244.6	495
22	Cost of Line Less Contribution-In-Aid-of-Construction					
23	Overhead	$1,054,975	$2,369,991	$2,386,449	$4,641,232	$9,397,672
24	Underground	$19,430	$121,438	$121,438	$242,875	$485,751
25	Total	$1,074,405	$2,491,429	$2,507,887	$4,884,107	$9,883,423
26	Cost per Mile					
27	Overhead	$19,830	$19,816	$19,821	$19,817	
28	Underground	$24,288	$23,353	$23,353	$23,353	
29	Total	$19,896	$19,963	$19,967	$19,968	
30	Cost per Service					
31	Overhead	$823	$823	$823	$823	
32	Underground	$1,214	$1,214	$1,214	$1,214	
33	Total	$828	$836	$836	$1,692	

* Cost shown on Line 25 already reflects the Contribution in Aid of Construction