Warren RECC
RURAL ELECTRIC COOPERATIVE CORPORATION

951 Fairview Avenue
Post Office Box 1118 • Bowling Green KY 42102-1118
Phone: 270.842.6541 • Fax: 270.781.3299
www.wrecc.com

April 6, 2005

RECEIVED

APR 0 8 2005

PUBLIC SERVICE
COMMISSION

Mr. Jason Bentley
General Counsel
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

Dear Mr. Bentley:

RE: An Assessment of Kentucky's Electric Generation, Transmission, and Distribution Needs – Administrative Case Number 2005-00090

We are responding to your request for information concerning the above-referenced case. You will find enclosed the original and ten copies of our response to Item Nos. 1, 2, 5, and 17-33 of Appendix B. These questions were answered jointly by myself and our Vice President of Operations, Mike Eastridge. We would like a copy of the final report if possible.

If you have any questions, please give us a call.

Sincerely,

Thomas A. Martin

Thomas A. Martin, P.E.
Vice President of Technical Services

TAM/mmb
Enclosures

APPENDIX B
APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 2005-00090
DATED MARCH 10, 2005

1. Provide a summary description of your utility's resource planning process. This should include a discussion of generation, transmission, demand-side, and distribution resource planning.

   Warren RECC, located in Bowling Green KY, is a distribution cooperative. It has attained its generation from the Tennessee Valley Authority through an all-requirements contract since 1942. On April 1, 2003, Warren RECC gave notice to TVA to cancel its power contract effective April 1, 2008. Subsequently, Warren RECC signed an all-requirements contract with East Kentucky Power Cooperative in Winchester KY. This contract has a 33-year term.

   All generation resource planning has been provided by TVA and EKPC will take over that role in 2008. This is also true for transmission at 161 kV and above. Warren RECC does own around 200 miles of 69 kV transmission line which it uses to feed it 35 distribution substations. These 69 kV facilities will continue to be owned by Warren RECC after the 2008 changeover to EKPC. Warren RECC has historically performed all of its distribution resource planning in-house primarily in the form of Construction Work Plans (CWP), Long Range Plans (LRP) and other planning activities required by the Rural Utility Service (RUS). Construction Work Plans are performed on a 4-year basis and Long Range Plans on a 10-year basis.

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 5 years and indicate which, if any, were implemented.

      Warren has implemented several new technologies in recent years, mostly in the area of automation. Some examples are:

      - Geographic Information System where all trucks have access to facilities and customer information on a laptop computer.
      - Interactive Voice Response (IVR) system to take and process customer calls on outages.
      - Outage Management System for Dispatch to determine location and causes of outages and to dispatch resources more efficiently.

- Work Order Management System (WOMS) designed to manage all work orders. Reports used to shorten response times to customers.
- Automated Customer Information System (TeleLinks) used to provide customer information, callbacks and certain transactions after hours.
- Supervisory Control and Data Acquisition (SCADA) system enhancements to monitor more data points from substations and line devices.

b. If no, explain in detail why new technologies are not considered.

~~3. Is your utility researching any renewable fuels for generating electricity?~~

~~a. If so, what fuels are being researched?~~

~~b. What obstacles need to be overcome to implement the new fuels?~~

~~4. Provide actual and weather-normalized annual native load energy sales for calendar years 2000 through 2004. Provide actual annual off-system energy sales for this same period disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to show separately those sales in which your utility acts as a reseller, or transporter, in a power transaction between two or more other parties.~~

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.

As a distribution cooperative, there is no breakdown into native, firm or non-firm, or off-system.

Year	Coincident Peak Demand (MW)
2000	294
2001	310
2002	317
2003	306
2004	318
2005	342

~~6. Provide a summary of monthly power purchases for calendar years 2000 through 2004 disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases in which your utility acts as a~~

~~reseller, or transporter, in a power transaction between two or more other parties. Include the average cost per megawatt-hour for each purchase category.~~

~~7. Provide the most current base case and high case demand and energy forecasts for the period 2005 through 2025, if available. If the current forecast does not extend to 2025, provide forecast data for the longest forecast period available. The information should be disaggregated into (a) native load, firm and non-firm demand; and (b) off-system load, both firm and non-firm demand.~~

~~8. Provide the target reserve margin currently used for planning purposes, stated as a percentage of demand, and a summary of your utility's most recent reserve margin study. If this target reserve margin has changed since 2002, provide the prior target reserve margin and explain the reasons for the change. If the target reserve margin is expected to be reevaluated in the next 3 years, explain the reasons for the reevaluation.~~

~~9. For the period 2005 through 2025, provide projected reserve margins stated in megawatts ("MW") and as a percentage of demand. Identify projected deficits and current plans for addressing these deficits.~~

~~10. Provide the following information for every generation station operated in Kentucky.~~

~~a. Name.~~

~~b. Location (including county).~~

~~c. Number of units.~~

~~d. Date in service for each unit.~~

~~e. Type of fuel for each unit.~~

~~f. Net rating (MW) for each unit.~~

~~g. Emission control equipment in service (list by type).~~

~~h. Date emission control equipment in service.~~

~~11. Provide a summary of any planned base load or peaking capacity additions to meet native load requirements in the years 2005 through 2025. Include capacity additions by the utility, and those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.~~

~~12. What is the estimated capital cost per KW and energy cost per kWh for new generation by technology?~~

13. ~~If current plans for addressing projected capacity deficits include the addition of gas-fired generation, describe the extent to which fluctuations in natural gas prices have been incorporated into these plans. Explain how fluctuations in natural gas prices may have altered the results of previous plans.~~

14. ~~Provide a summary of any permanent reductions in utilization of generation capacity due to Clean Air Act compliance from 2000 through 2004. Identify and describe any forecasted reductions during the 2005 through 2025 period.~~

15. ~~Provide a summary of all forced outages and generating capacity retirements occurring during the years 2000 through 2004.~~

16. ~~Provide a summary of the utility's plans for the retirement of existing generating capacity during the 2005 through 2025 period.~~

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

    a. Annual DSM budget,

    b. Demand and energy impacts.

    c. The currently scheduled termination dates for the programs.

    Warren RECC currently has no formal demand-side management programs. TVA, Warren RECC's wholesale provider, has some commercial and industrial time-of-use rates but they do not offer enough of an incentive for most industries to modify their usage patterns. Warren has historically had a few of the largest users on an interruptible rate called Variable Price Interruptible (VPI) but the savings are not as significant as they once were and no customers currently utilize this rate.

18. Provide your utility's definition of "transmission" and "distribution."

    Distribution is all of the system operated at distribution voltage levels. The only distribution voltage that is used is 7200/12,470Y.

    Transmission at Warren RECC is actually what is referred to in the industry as "sub-transmission." This for Warren RECC is the 200 miles or so of 69 kV transmission or sub-transmission, more appropriately. Warren RECC takes power from TVA at 161 kV and owns some 161 kV terminating equipment but has very little 161 kV transmission line facilities.

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

Utility Connected to:	Voltage	Capacity
TVA (primary supply)	161 kV and 69 kV	Approx. 500 MW
Glasgow EPB	69 kV	Approx. 35 MW
Franklin EPB (part of contractual agreement with TVA)	69 kV	13 MW
Kentucky Utilities	69 kV	Approx. 50 MW
Bowling Green Municipal Utilities	69 kV	Approx. 30 MW

20. Provide the peak hourly MW transfers into and out of each interconnection for each month of the last 5 years. Provide the date and time of each peak.

    The transfers in to and out of the interconnection points in the table above, with the exception of the primary delivery points with TVA, are used only for emergency backfeeds. All connections are operated as radial and are seldom used. This data is available but is somewhat difficult to assemble. Please advise if this type of data is what is actually desired.

21. Identify any areas on your utility's system where capacity constraints, bottlenecks, or other transmission problems have been experienced from January 1, 2003 until the present date. Identify all incidents of transmission problems by date and hour, with a brief narrative description of the nature of the problem. Provide the MW transfers for each of your utility's interconnections for these times.

    In Warren RECC's power supply arrangement with TVA, TVA has an interconnection arrangement with Kentucky Utilities in which the northern portion of the Warren RECC territory (approximately 20% of the energy) is actually supplied from KU's grid. Warren has not experienced specific problems from this arrangement; however, there are some capacity problems with this arrangement. TVA and KU have a firm agreement for 35 MW to cover load in this area. These loads occasionally exceed this agreement level and may eventually cause problems until addressed in the new power supply agreement with EKPC.

    The only other transmission capacity problems experienced by Warren RECC occurred in the summer of 2001 and 2002 and possibly 2003. The problems caused low voltage on the 161 kV system for short periods. TVA informed Warren RECC that these events were caused by excessive north-south flows across their system due to events that were not completely understood at the time.

22. Provide details of any planned transmission capacity additions for the 2005 through 2025 period. If the transmission capacity additions are for existing or

expected constraints, bottlenecks, or other transmission problems, identify the problem the addition is intended to address.

Defining transmission as 161 kV and above, there is some 90 miles of 161 kV transmission line to be constructed by EKPC to meet the April 1, 2008 change described earlier. This transmission, along with EKPC's request to TVA for three interconnection points, will provide the contract path from EKPC generation to Warren RECC's load.

Warren RECC will have numerous 69 kV (sub-transmission) projects over that time period to integrate future new substations into the 69 kV system. This will primarily consist of tap lines from new stations to existing 69 kV lines.

23. Is your utility researching or considering methods of increasing transmission capacity of existing transmission routes? If yes, discuss those methods.

No. EKPC is responsible for this activity in the future.

24. Provide copies of any reports prepared by your utility or for your utility that analyze the capabilities of the transmission system to meet present and future needs for import and export of capacity.

TVA is responsible for this activity through April 1, 2008 and EKPC afterwards.

25. Provide the following transmission energy data forecast for the years 2005 through 2025.

a. Total energy received from all interconnections and generation sources connected to your transmission system.

b. Total energy delivered to all interconnections on your transmission system.

c. Peak demand for summer and winter seasons on your transmission system.

Again, these activities would be the responsibility of those as listed in 24 above. EKPC has the most recent projections for Warren RECC future loads.

26. Provide the yearly System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"), excluding major outages, by feeder for each distribution substation on your system for the last 5 years.

	2000	2001	2002	2003	2004
SAIDI	2.53	1.79	3.23	1.45	1.84
SAIFI	1.14	1.12	1.1	1.07	1.02

27. Provide the yearly SAIDI and SAIFI, including major outages, by feeder for each distribution substation on your system for the last 5 years. Explain how you define major outages.

	2000	2001	2002	2003	2004
SAIDI	3.79	1.89	3.37	1.51	2.01
SAIFI	1.14	1.12	1.1	1.1	1.06

28. What is an acceptable value for SAIDI and SAIFI? Explain how it was derived.

SAIFI Goal: 1.5 hours per year (excluding extreme storms)
SAIDI Goal: 90 minutes per year (excluding extreme storms)
CAIDI Goal: 1.0 hour / outage (excluding extreme storms)
ASAI Goal: 99.983 annually (excluding extreme storms)

29. Provide the yearly Customer Average Interruption Duration Index (CAIDI") 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.

	2000	2001	2002	2003	2004
CAIDI	3.3	1.69	3.07	1.4	1.89
CAIDI w/o	2.22	1.60	2.94	1.36	1.80

The CAIFI index is not available.

30. Identify and describe all reportable distribution outages from January 1, 2003 until the present date. Categorize the causes and provide the frequency of occurrence for each cause category.

Outage Cause Report

	2003	2004
Bird / Animal	34	150
Equipment Failure	90	124
Extreme Storm	6	123
Fire	8	10
Ice / Snow	21	9
Lightning	22	59
Man Caused	18	67
Overload	9	19
Trees	72	235
Unknown	496	1,087
Total Causes	**776**	**1,883**

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

a. How does your utility measure reliability?
Milsoft software as part of our outage management system.

b. How is the program monitored?
24/7 Dispatch Center

c. What are the results of the system?

d. How are proposed improvements for reliability approved and implemented?
We identify problem areas using our outage management system, customer surveys and load studies to identify improvement priorities. District Managers approve and implement smaller projects and those affecting immediate service to the member. Larger projects are approved by the Vice Presidents of Engineering and Operations.

32. Provide a summary description of your utility's:

a. Right-of-way management program. Provide the budget for the last 5 years.

b. Vegetation management program. Provide the budget for the last 5 years.

	FY00	FY01	FY02	FY03	FY04
Right-of-Way (GL 59310)	$1,087,788	$1,410,352	$1,347,108	$1,364,315	$2,174,660

c. Transmission and distribution inspection program. Provide the budget for the last 5 years.

Transmission Inspections Helicopter (GL 56300)	$16,105	$10,000	$8,176	$16,810	$7,774
Distribution Inspections *** (GL 58300 &/or 58310)	$69,962	$3,615		$114,270	$117,424
TOTALS	**$1,173,855**	**$1,423,967**	**$1,355,284**	**$1,495,395**	**$2,299,858**

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.

Following are excerpts from Warren RECC Engineering Design Criteria:

4.6.3 Certain equipment and construction methods formerly used to develop the system have had an unacceptable impact on system reliability. The following replacement programs have been implemented to systematically reduce the effect that these methods and materials have on reliability:

4.6.3.1 ACSR with steel armor rods replacement – ACSR conductor originally installed with steel armor rods have demonstrated unacceptably high failure rates due to the corrosion created by the dissimilar metals. Years of exposure result in the corrosion of the steel core and reduce the rated strength of the conductor.

4.6.3.2 Copper weld conductor replacement – Copper weld conductor has demonstrated unacceptably high failure rates resulting from the effects of corrosion and conductor brittleness.

4.6.4 Facilities which are found to be in poor condition or present a danger to the public shall be replaced. Such facilities shall be identified using field proven techniques such as pole sounding, infrared inspection, excessive splices per mile of conductor, and/or visual inspection.

4.6.5 Recent member satisfaction surveys indicate that permanent and intermittent outages are the issues of principle concern. In order to address these concerns, protective device coordination principles need to be tailored to meet the dynamic characteristics of each feeder. Since previous coordination rules of thumb are no longer practical, a coordination study will need to be conducted on each feeder. Once complete, this study will need periodic review. To the extent possible, the coordination projects necessitated by these feeder coordination studies will be incorporated into this construction work plan.

Other guiding principles followed when determining if whether plant should be replaced:

<u>Distribution Inspections</u> – Distribution facilities are inspected on a regular basis. Facilities that are found to present an imminent hazard to public safety are replaced immediately. Those facilities that are likely to fail prior to the next routine inspection are also replaced, but are not prioritized above other routine work unless the circumstances merit. Facilities flagged for replacement are periodically re-inspected to ensure appropriate assessment techniques are being applied. The root cause of facility failures that occur prior to replacement are periodically reviewed and the inspection process modified to suit.

Attached as Addendum A is a spreadsheet that estimates future replacement costs.

Addendum A

	1	2	3	4	5	6	7
Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Cost of Pole Replacements	$ 631,692	$ 653,801	$ 676,684	$ 700,368	$ 724,881	$ 750,252	$ 776,511
Cost of CW Conductor Replacements	$ 351,704	$ 364,014	$ 376,754	$ 389,941	$ 403,589	$ 417,714	$ 432,334
Cost of Corroding ACSR Replacements	$ 701,189	$ 725,730	$ 751,131	$ 777,420	$ 804,630	$ 832,792	$ 861,940
Total Estimated Cost of Replacements:	$ 1,684,585	$ 1,743,545	$ 1,804,569	$ 1,867,729	$ 1,933,100	$ 2,000,758	$ 2,070,785

	8	9	10	11	12	13	14
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Cost of Pole Replacements	$ 803,689	$ 831,818	$ 860,931	$ 891,064	$ 922,251	$ 954,530	$ 987,939
Cost of CW Conductor Replacements	$ 447,466	$ 463,127	$ 479,337	$ 496,113	$ 513,477	$ 265,725	$ 275,025
Cost of Corroding ACSR Replacements	$ 892,108	$ 923,332	$ 955,648	$ 989,096	$ 1,023,714	$ 529,772	$ 548,314
Total Estimated Cost of Replacements:	$ 2,143,262	$ 2,218,277	$ 2,295,916	$ 2,376,273	$ 2,459,443	$ 1,750,027	$ 1,811,278

	15	16	17	18	19	20	21
Year	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Cost of Pole Replacements	$ 1,022,516	$ 1,058,304	$ 1,095,345	$ 1,133,682	$ 1,173,361	$ 1,214,429	$ 1,256,934
Cost of CW Conductor Replacements	$ 284,651	$ 294,614	$ 304,925	$ 315,597	$ 326,643	$ 338,076	$ 349,909
Cost of Corroding ACSR Replacements	$ 567,505	$ 587,368	$ 607,926	$ 629,203	$ 651,225	$ 674,018	$ 697,609
Total Estimated Cost of Replacements:	$ 1,874,672	$ 1,940,286	$ 2,008,196	$ 2,078,483	$ 2,151,230	$ 2,226,523	$ 2,304,451