COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF THE RELIABILITY	)	
MEASURES OF KENTUCKY'S	)	ADMINISTRATIVE
JURISDICTIONAL ELECTRIC	)	CASE NO. 2006-00494
DISTRIBUTION UTILITIES AND CERTAIN	)	
RELIABILITY MAINTENANCE PRACTICES	)	

O R D E R

BACKGROUND

The Commission initiated this investigation of the reliability assessment measures used by jurisdictional electric utilities, and the vegetation management practices related to electric distribution systems by Order dated December 12, 2006. All jurisdictional electric distribution utilities were made parties to this proceeding.[1] The Commission noted under KRS 278.030(2) that utilities are required to furnish adequate, efficient, and reasonable service. Adequate service is defined in KRS 278.010(14) as having sufficient capacity to meet maximum demand "and to assure such customers of reasonable continuity of service."

Duke Energy Kentucky, Inc. ("Duke") files certain reliability information as set forth in its settlement agreement when it acquired The Union Light, Heat and Power

[1] Big Rivers Electric Corporation ("Big Rivers") and East Kentucky Power Cooperative, Inc. ("EKPC") were not made parties because they are generation and transmission companies and do not have distribution systems.

Company in 2005.[2] Kentucky Power Company ("Kentucky Power") also files a variety of reliability information with the Commission pursuant to the settlement agreement accepted as part of the merger of American Electric Power Company, Inc. with Central and South West Corporation in June 1999.[3] In addition, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") file a variety of reliability information as required by their transfer to what is now E.ON U.S. LLC.[4] However, the other jurisdictional utilities are currently required to report only those outages lasting four or more hours and affecting 500 or more customers.[5] While this provides various indications of reliability to the Commission, it only addresses large outages. As such, these reports do not provide the Commission with other pertinent information regarding systems experiencing multiple small outages, or chronic outage problems to the same set of customers. The rural electric cooperatives do provide copies of their Rural Utilities Service ("RUS") filings which provide a variety of additional reliability information.

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[2] Case No. 2005-00288, Joint Application of Duke Energy Corporation, Duke Energy Holding Corp., Deer Acquisition Corp., Cougar Acquisition Corp., Cinergy Corp., The Cincinnati Gas & Electric Company, and The Union Light, Heat and Power Company for Approval of Transfer and Acquisition of Control, final Order dated November 29, 2005.

[3] Case No. 1999-00149, Joint Application of Kentucky Power Company, American Electric Power Company, Inc., and Central and South West Corporation Regarding a Proposed Merger, final Order dated June 14, 1999.

[4] Case No. 2000-00095, Joint Application of Powergen Plc, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger, Final Order dated May 15, 2000; and Case No. 2001-00104, Joint Application of E.ON AG, Powergen Plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition, final Order dated August 6, 2001.

[5] 807 KAR 5:006, Section 26(1)(c).

In Case No. 2005-00090,[6] the Commission noted that more detailed reliability reporting could provide the Commission with additional information about a utility's ability to provide adequate service. Also in Case No. 2005-00090, the Commission found that right-of-way maintenance and vegetation management are important parts of distribution reliability management.

Information was collected from the utilities through two rounds of data requests, an informal conference, and a formal hearing at which the Commission presided. Staff attempted to build a record to support an answer to four broad questions regarding reliability and vegetation management:

1. Should the Commission require regular, periodic reporting of reliability information?

2. Should the Commission establish a reliability standard?

3. Should the Commission establish a minimum clearance standard for distribution lines?

4. Should the Commission establish a minimum vegetation management plan requirement?

SHOULD THE COMMISSION REQUIRE PERIODIC REPORTING OF RELIABILITY INFORMATION?

Discussion of the Record

All utilities are measuring, monitoring, or tracking distribution reliability, or have the ability to do so.[7] Of the utilities that track reliability information, eight do not exclude major events or large storms from their data. There were several methods utilized by

[6] Case No. 2005-00090, An Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs, final Order dated September 15, 2005.

[7] Responses to Order dated December 12, 2006, Items 1 and 8.

the utilities to determine a major event.[8] The Institute of Electrical and Electronics Engineers ("IEEE") standard number 1366-2003 "Guide for Electric Power Distribution Reliability Indices" standard ("IEEE Standard") was used by three utilities to define a major event. Others used outage duration times or fraction of customers affected as criteria for defining a major event.

All of the utilities maintain a list of outage causes, although there is no common list universally used by the companies.[9] All but two utilities responded that they were capable of collecting reliability information by circuit, but all were capable of collecting reliability information on a system-wide basis.[10]

The utilities were split on the issue of requiring regular reporting of reliability information to the Commission. The investor-owned utilities either stated it is appropriate or replied in a neutral way. They stated that if the Commission does require reporting of reliability information, standardized criteria for reporting should be developed by the Commission. Two of the IOU's recommend adopting the IEEE Standard for electric power distribution reliability indices. However, the Commission was cautioned not to use the information to compare one utility to another as many factors must be taken into account when comparing the reliability of two utilities.[11]

The IEEE Standard defines a number of indices for tracking reliability. The most commonly used indices are the system average interruption duration index ("SAIDI"),

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[8] Id., Item 2.

[9] Id., Item 7.

[10] Id., Items 4 and 8.

[11] Response to staff questions posed at informal conference held March 8, 2007, Items 4, 5, and 6.

the system average interruption frequency index ("SAIFI"), the customer average interruption duration index ("CAIDI"), and the customer average interruption frequency index ("CAIFI"). SAIDI indicates the total duration of interruption for the average customer during the period of time measured, while SAIFI indicates how often the average customer experiences an outage. CAIDI represents the average time required to restore service. CAIFI provides the frequency of interruptions for those experiencing interruptions.

The rural electric distribution cooperatives would prefer that the Commission adopt the RUS Form 7 reporting requirement, which requires the utilities to calculate the average number of hours a customer on their system is without service in a given year. If this number is greater than five hours, the rural electric cooperative is required to develop an improvement plan to reduce service outages to less than 5 hours per year.[12]

Consensus among the utilities appears to support reliability reporting at the system level only. While most utilities are capable of collecting information at lower levels, and do so for internal analysis, they believe reporting the smaller divisions of the system would create confusion. To be able to accurately compare dissimilar areas of a system, they argue, one would need to take into account the geography, history, age, and land use to make a determination of the differences in reliability given two different index values.[13]

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[12] Id.

[13] Id., Item 4.

Findings

The Commission finds that it should require the electric distribution companies to provide regular periodic reporting of reliability information. Although over the years there have only been isolated findings relative to the adequacy of service, the current outage reporting does not provide the Commission with sufficient information to judge the adequacy of service without initiating a comprehensive investigation. Reporting should be based on the criteria and definitions set forth in the IEEE Standard, including the criteria for omitting events classified as major event days. Reports should be provided annually and should include the system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), and the customer average interruption duration index (CAIDI).

Reporting of the SAIFI and SAIDI indices will provide the Commission with information regarding the frequency an average customer can expect to suffer an interruption, and the number of hours an average customer is without service. This can help the Commission determine if a system has frequent outages, and how well the utility responds in restoring service to its customers following an outage. Reporting CAIDI, which removes the uninterrupted customers from the index calculation, can help provide a clearer picture of the amount of time interrupted customers are actually without service.

The Commission does not believe it is appropriate to require the utilities to report each of their substations or circuits because analyzing data below the system-wide level creates two problems. First, as the unit which is being measured gets smaller, the volatility of the measurement gets larger. Single customer outages can become magnified as the size of the customer pool is reduced, so that a customer on a sparsely populated circuit would have more influence on the resulting index value than a customer on a densely populated circuit. Reporting the entire system as one index value places all customers within a utility on equal footing. Second, each circuit in a system has characteristics which distinguish it from other circuits. All of a circuit's characteristics would need to be taken into account when making comparisons across utilities. Considering the volume of data from the number of circuits involved, and then adding in considerations of population density, vegetation coverage, age of equipment, topography, rural versus urban, etc., the resulting reports would likely not be of any practical use on a regular basis. The Commission finds that while reporting on all the subparts of a utility's system is not currently practical, utilities should provide some analysis of the annual reliability results at a more granular level than system wide alone. Therefore, the Commission finds that the utilities should provide an analysis of their ten worst performing circuits on the system for each year of the reporting period. The utilities should also include an analysis of the cause of the poorer performance, and any corrective actions taken or planned to improve the performance. The utilities should collect and maintain the reliability information to be able to provide the Commission with the reports on the ten worst circuits.

If the weather results are normalized according to the IEEE Standard, then conclusions can be drawn regarding the effect of weather and of a utility's operating decisions on its system reliability. For the indices to have the most significance, the Commission must have historical reference points. During the hearing, participants stated that at least 5 years of information should be reviewed, and preferably 10 years in order for the information to be meaningful. The Commission believes that the annual reliability reports should include enough history to allow the utility, the Commission and other interested parties to determine trends. Therefore, the Commission finds that each utility should be required to report a minimum of 5 years of data each year. The Commission further encourages each utility to analyze and report as many years as is practical, given the characteristics of their systems; however, only the most recent 5 years will be required.

In addition, part of the annual reporting of reliability should include how well the utility implemented its vegetation management plan, and what changes to the plan will be implemented in the coming year.

The reports should be filed with the inspection records of the utility in the Commission's offices. The Engineering Division will incorporate these reports into the electric utility inspection process. This will ensure the reports are reviewed and investigated at least once per year and do not become a paperwork exercise for the utilities.

Reports should be based on a calendar year (January to December) and should be provided to the Commission by the first business day in April in the year immediately following the reporting year. The reports should include the following:

1. The System Average Interruption Duration Index ("SAIDI"), the System Average Interruption Frequency Index ("SAIFI"), and the Customer Average Interruption Duration Index ("CAIDI").

2. The Institute of Electrical and Electronic Engineers standard number IEEE Std 1366 guide (latest version) to define the terms used in the reliability report.

3. Each index calculated for, at a minimum, each of the preceding five 12-month periods.

4. Each index calculated for a utility's complete system.

5. Durations of outages measured and reported in minutes.

6. For each index an analysis of the contributing causes for the reporting year. The analysis to include the outage cause categories and the value each category contributed to the final index value. If more than ten categories are tracked, only the ten most significant categories.

7. A list of the ten worst performing circuits for the reporting year for each index value. For each circuit so listed, the report to identify the circuit, the index value calculated for the circuit, and the major outage category contributing to the circuit's performance. If the utility cannot track information by circuit, the information for the smallest subdivision of its system possible.

SHOULD THE COMMISSION ESTABLISH A RELIABILITY STANDARD?

Discussion of the Record

The utilities were asked to describe how the reliability information was used within their respective organizations. In general, the utilities responded that the reliability information was used to identify trends and to identify problem areas within their systems.[14] The information is also used in preparing construction work plans, maintenance plans, and system performance improvement plans. Several utilities have

[14] Case No. 2006-00494, Second Data Request of Commission Staff to Jurisdictional Electric Distribution Utilities, February 9, 2007, Items 1 and 3.

established internal targets for system reliability performance; failure to meet a target usually results in a corrective action plan.[15]

It was clear from the responses of the utilities that they do not support a Commission-established reliability performance standard. The utilities emphasized that they each have different customer demographics, construction histories, geography, vegetation issues, population densities, and other factors which make meaningful comparison among utilities difficult. Instead, the utilities assert that the Commission should focus on comparing their current performance to their past performance in order to determine if current management practices are improving or degrading system reliability over a period of several years.[16]

Findings

The Commission finds that it should not establish a formal reliability standard at this time. The Commission does not have broad evidence of inadequate service or sufficient comparative information to conclude that imposition of a reliability standard is appropriate at this time.

When the reporting requirements are implemented as described above, another tool to monitor reliability will be provided to the Commission that can be used in addition to the reviews of the Commission's electric inspectors and information from contacts with the Consumer Services Division. The Commission has the authority necessary to pursue specific issues, and can, as a result of an investigation, impose fines or other corrective action.

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[15] Id., Item 2.

[16] Response to staff questions posed at informal conference held March 8, 2007, Items 8 and 9.

At this time, the Commission does not believe a statewide standard is appropriate. Due to the differences in geography, customer density, age of infrastructure, past operating practices, and other factors, each utility's system has a different expected reliability. A standard set at the level which could reasonably be attained by all utilities, would likely be too lenient for some utilities, and if set at a level expected by the best performing utilities, would likely be unrealistic for other utilities.

The Commission also finds that it is not appropriate to set individual utility standards at this time, as we do not have sufficient data to determine the statistical expectation for each utility. However, after several years of data have been provided, the Commission will be able to determine the expected value and a reasonable amount of variability for each utility and, after review, the Commission may choose to establish utility-specific expectations or reliability standards. Even though the Commission will not establish a reliability standard at this time, each utility is encouraged to develop internal reliability goals or standards for their systems.

SHOULD THE COMMISSION ESTABLISH A MINIMUM CLEARANCE STANDARD FOR OVERHEAD DISTRIBUTION LINES?

Discussion of the Record

The utilities provided a significant amount of information and discussion relating to their vegetation management practices in Case No. 2005-00090 as well as in this proceeding. Based on the information provided, generally all utilities determine when right-of-way maintenance is required either by cycle timing, specific circuit-to-station reliability results, or by inspection of the right-of-way.[17] Right-of-way maintenance work

[17] Responses to Order dated December 12, 2006, Item 11.

is typically performed by contractors, with utility personnel responsible for reviewing and approving completed work.[18] Utility right-of-way clearing cycles range from 4 years to 7 years, with one utility stating that no specific time table was used to plan right-of-way maintenance.[19]

Because many of the rural electric distribution cooperatives cited it as a guide they followed and other utilities described similar guides, the utilities were asked to review the RUS drawing M1.30G "RIGHT-OF-WAY CLEARING GUIDE" and comment on whether this clearance standard should be implemented for all overhead distribution lines. This drawing indicates that all trees and tree limbs within a certain horizontal distance from the conductors should be removed (in essence, a 30 foot wide clearing). All utilities responded that such a standard is not appropriate in all situations. More particularly, its use is very problematic when landowners object to the removal of shade trees and when lines run through urban areas near structures.[20]

The utilities were asked to describe their legal rights regarding rights-of-way over property not owned by the utility. Utilities obtain easements either expressly or through operation of law when the distribution lines are constructed. These easements allow the utilities to access and maintain their poles and conductors, but do not necessarily convey legal rights to remove trees or branches beyond what is necessary to maintain operational safety. Several utilities predicted that requiring them to clear rights-of-way of all trees within a certain distance of the conductors would result in lawsuits and

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[18] Id., Item 12.

[19] Id., Item 14.

[20] Responses to Second Data Request of Commission Staff to Jurisdictional Electric Distribution Utilities, February 9, 2007, Item 8(a).

customer dissatisfaction. Further, the utilities indicated that they do not believe it would be feasible or appropriate for the Commission to establish minimum right-of-way clearance standards.[21]

Findings

The Commission finds that it is not appropriate to establish a minimum clearance standard at this time. The utilities identified several reasons why the Commission should not establish a minimum clearance standard. Based on the utilities' comments, we have determined that the degree of flexibility required by the utilities to accommodate landowner rights and desires would make promulgating a fair standard very difficult or impractical. Simply requiring a minimum clearance from conductors would likely result in widespread customer dissatisfaction and could lead to litigation over private property rights versus Commission regulatory authority and utility easement rights.

As the utilities noted, vegetation management is only one factor which affects the reliability of a distribution system. It is perhaps the most visible factor, but not necessarily the dominant one. As the Commission collects the reliability information required above, poor or inadequate vegetation management practices might be indicated in the analysis of the results. Further investigation of the system may then reveal if vegetation management practices need improvement or further review which can be undertaken at that time. As with the reliability standard discussed above, the Commission will not establish a minimum clearance standard for overhead distribution lines at this time. However, after several years of reliability information has been

[21] Response to staff questions posed at informal conference held March 8, 2007.

collected, the Commission may determine that a clearance standard or more formal guidance is necessary to ensure reliability.

SHOULD THE COMMISSION ESTABLISH A MINIMUM VEGETATION MANAGEMENT PLAN REQUIREMENT?

Discussion of the Record

The Commission did not specifically ask the utilities if it should require the utilities to develop vegetation management plans or establish minimum requirements to be included in such plans. However, the utilities addressed this issue fairly specifically in discussing the need for standards for right-of-way clearing and in discussing vegetation management issues in general. Generally, the utilities took the position stated by Duke that if the Commission determined that "greater monitoring of vegetation management practices is necessary, the Commission should permit each utility to design and file its own, individually-tailored vegetation management plan to address each utility's specific needs."[22] In its brief, Kentucky Power addresses the issue more specifically. Kentucky Power states that although a number of utilities have developed their own vegetation management plans, there is no recognized model plan. Kentucky Power argues that the evidence in the record supports the position that a vegetation management plan for a specific utility must be based on the individual characteristics of that utility and its service territory. Therefore, Kentucky Power argues, vegetation management plans are simply tools and if a utility chooses to deviate from its plan, that deviation should not

[22] Brief of Duke Energy Kentucky, Inc., filed June 29, 2007.

serve as a basis for enforcement. The Commission, according to Kentucky Power, should focus on the multi-year trend of the utility's reliability indices.[23]

Findings

The Commission finds it should require the utilities to develop a formal vegetation management plan. This requirement should not be burdensome because almost all of the utilities have developed such plans – although some may be more formal than others. Based on the record of this proceeding, the Commission has concluded that the utilities are best positioned to determine how to effectively maintain their systems, and should be allowed flexibility in developing the specific details of their plan. However, the Commission has determined that each plan should meet certain minimum requirements. These are:

- Identify the right-of-way clearing cycle.
- Identify the reliability criteria and reliability reports used to develop the vegetation management plan and those regularly reviewed as part of the monitoring of plan effectiveness.
- Explain how a utility determines when to perform maintenance.
- Explain how the effectiveness of the plan is evaluated.

As we stated in the section relating to reliability reporting, part of the annual reporting of reliability should include how well the utility implemented its plan, and what changes to the plan will be implemented in the coming year.

[23] Post-Hearing Brief of Kentucky Power Company, filed June 29, 2007.

IT IS THEREFORE ORDERED that:

1. All jurisdictional distribution utilities shall file annual reliability reports with the Commission as described in this Order. Reports may be provided on paper or on CD, DVD, USB memory card, or 3.5" diskette in .xls, .doc, or .pdf format.

2. Jurisdictional distribution utilities shall develop a vegetation management plan as described in this Order and shall file a copy of the plan with the Commission within 60 days of the date of this Order. Plans may be provided on paper or on CD, DVD, USB memory card, or 3.5" diskette in .xls, .doc, or .pdf format.

3. Reports and plans shall be addressed to: Director of Engineering, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

Done at Frankfort, Kentucky, this 26th day of October, 2007.

By the Commission

ATTEST:

Executive Director