FLEMING-MASON ENERGY
COOPERATIVE, INC.

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February 22, 2007

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PUBLIC SERVICE
COMMISSION

Public Service Commission
P. O. Box 615
Frankfort, Kentucky 40602

Dear Sirs:

Enclosed is the response of Fleming-Mason Energy to the Public Service Commission Order Regarding Administrative Case No. 2006-0494, an Investigation of Kentucky's Jurisdictional Electric Distribution Utilities and certain Reliability Maintenance Practice.

Sincerely,

Anthony P. Overbey
President and CEO

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

SECOND DATA REQUEST OF COMMISSION STAFF TO JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES

Jurisdictional electric distribution utilities ("distribution utilities") are requested, pursuant to 807 KAR 5:001, to file with the Commission the original and six copies of the following information, with a copy to all parties of record. The information requested herein is due on or before February 23, 2007. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the person who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") may file one document as KU/LG&E including a separate response for each company within each tabbed response where necessary.

All electric distribution utilities are to respond to the following questions:

1. Describe in detail how the company utilizes all of the reliability measures it monitors.

2. Has the company determined an appropriate operating range or performance threshold based on these measures? If yes, identify.

3. Describe in detail how the company develops formal plans to address its worst performing circuits. If the company does not develop such plans, indicate so in the response.

4. Why are momentary outages excluded?

5. Why are major event days or major storms excluded?

6. Provide a hard copy citing of the Rural Utilities Service ("RUS") reliability monitoring or reporting requirements or, in the alternative, provide an accessible Internet site.

7. Provide and describe in detail any service restoration or outage response procedure utilized.

8. Refer to the RUS drawing M1.30G "RIGHT-OF-WAY CLEARING GUIDE" ("ROW Guide"), a copy has been provided in Appendix A.

a. Is this type of clearance requirement appropriate for all areas of a distribution system? If not, what types of exclusions or exceptions should be made?

b. If the distribution utility is not already following this guide, provide an estimate of the cost and time-line to implement.

9. Refer to North American Electric Reliability Corporation ("NERC") standard FAC-003-1 "Transmission Vegetation Management Program" ("NERC Standard"), a copy is attached in Appendix B.

a. Does the company prefer the type of standard described in the NERC Standard over the type of standard described in the ROW Guide? Explain why you prefer one over the other.

b. Refer to section R3 of the NERC Standard and substitute "distribution" for "transmission." Is the distribution utility capable of meeting the reporting requirements described in the section? If not, why not?

c. Again referring to section R3 as applied to distribution, how many sustained outages would be reportable for the calendar year 2006?

10. Provide and discuss any right-of-way maintenance standard which is preferable to those identified in questions 1 and 2 above.

<u>Duke Energy Kentucky is to respond to the following questions:</u>

11. How many substations are equipped with Supervisory Control and Data Acquisition ("SCADA")? How many are not?

12. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

<u>Kentucky Power is to respond to the following questions:</u>

13. How many substations are equipped with SCADA? How many are not?

14. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

<u>KU/LG&E are to respond to the following questions:</u>

15. How many substations are equipped with SCADA? How many are not?

16. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

17. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Big Sandy is to respond to the following question:

18. Why doesn't Big Sandy exclude any outages from its reliability measures?

Clark Energy is to respond to the following question:

19. Describe the value of the measures described in items 1 though 4 of Clark's response to Question No. 1 in Staff's first data request.

Farmers is to respond to the following question:

20. Can Farmers monitor System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") in addition to Customer Average Interruption Duration Index ("CAIDI")?

Grayson is to respond to the following questions:

21. Why doesn't Grayson monitor or track distribution reliability?

22. Does RUS require that Grayson report any distribution reliability measures or service interruptions?

23. Does Grayson have the capability to monitor SAIDI, SAIFI and CAIDI?

24. How does Grayson define a sustained outage?

Inter-County is to respond to the following question:

25. Can Inter-County monitor SAIFI and CAIDI in addition to SAIDI?

Jackson Energy is to respond to the following question:

26. Describe in detail the capabilities of the Outage Management Software to monitor outages and provide reliability-related information.

Jackson Purchase is to respond to the following questions:

27. Why doesn't Jackson Purchase exclude any outages from its reliability measures?

28. Describe in detail the capabilities of the new outage management and reporting system to monitor outages and provide reliability-related information.

Kenergy is to respond to the following questions:

29. Why doesn't Kenergy exclude any outages from its reliability measures?

30. How many substations are equipped with SCADA? How many are not?

31. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

32. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Licking Valley is to respond to the following question:

33. Can Licking Valley monitor SAIFI and CAIDI in addition to SAIDI?

Meade County is to respond to the following questions:

34. Why doesn't Meade County exclude any outages from its reliability measures?

35. Describe in detail the capabilities of the Hunt Turtle II AMI System relating to monitor outages and provide reliability-related information.

Nolin is to respond to the following questions:

36. How many substations are equipped with SCADA? How many are not?

37. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

38. Describe in detail the capabilities of the new AMR System to monitor outages and provide reliability-related information.

Owen is to respond to the following question:

39. Can Owen monitor SAIDI, SAIFI and CAIDI in addition to the measures noted in its response to Staff's First Data Request?

Salt River is to respond to the following questions:

40. Can Salt River monitor CAIDI in addition to SAIDI and SAIFI?

41. How many substations are equipped with SCADA? How many are not?

42. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

43. Describe in detail the capabilities of the AMR System to monitor outages and provide reliability-related information.

Shelby Energy is to respond to the following questions:

44. Can Shelby Energy monitor SAIDI, SAIFI and CAIDI in addition to the measures noted in its response to Staff's First Data Request?

45. Why doesn't Shelby Energy exclude any outages from its reliability measures?

46. How many substations are equipped with SCADA? How many are not?

47. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

South Kentucky is to respond to the following questions:

48. How many substations are equipped with SCADA? How many are not?

49. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

50. Describe in detail the capabilities of the Outage Management System to monitor outages and provide reliability-related information.

Taylor County is to respond to the following questions:

51. Can Taylor County monitor SAIFI and CAIDI in addition to SAIDI?

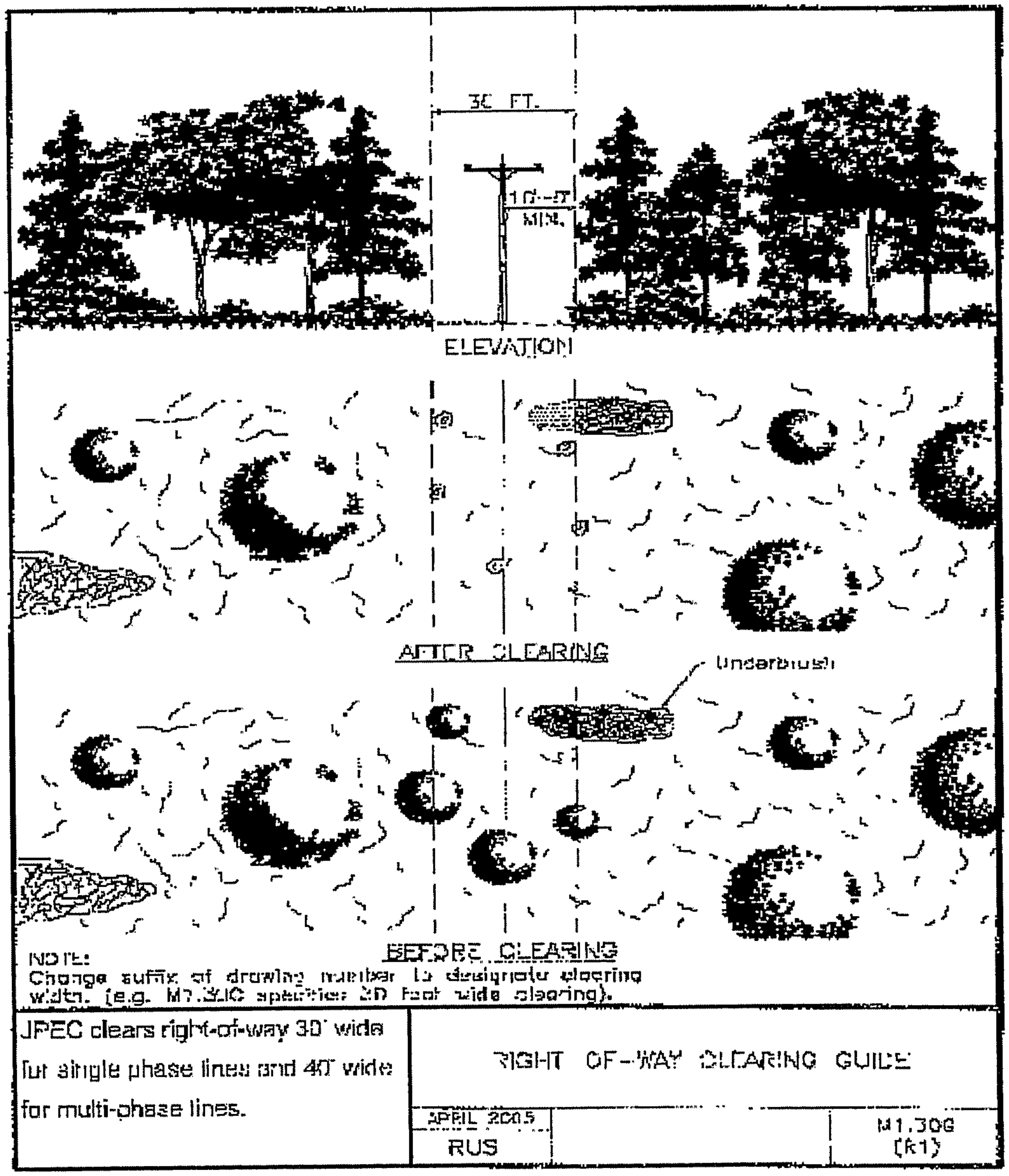
52. Why doesn't Taylor County exclude any outages from its reliability measures other than those where equipment automatically restores service?

Beth O'Donnell
Executive Director
Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

DATED February 9, 2007

cc: All Parties

Appendix A



30 FT.
MIN.
ELEVATION
AFTER CLEARING
Underbrush
BEFORE CLEARING
NOTE:
Change suffix of drawing number to designate clearing width. (e.g. M1.30G specifies 30 foot wide clearing).
JPEC clears right-of-way 30' wide for single phase lines and 40' wide for multi-phase lines.
RIGHT OF-WAY CLEARING GUIDE
APRIL 2005
RUS
M1.30G
(R1)

Appendix B

A. Introduction

1 **Title: Transmission Vegetation Management Program**

2 **Number:** FAC-003-1

3 **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. Applicability:

4.1. Transmission Owner.

4.2. Regional Reliability Organization.

4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5 Effective Dates:

5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications1 .

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   RRO

   NERC

   1.2. Compliance Monitoring Period and Reset

   One calendar Year

   1.3. Data Retention

   Five Years

   1.4. Additional Compliance Information

   The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

   2.1. Level 1:

   2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

   2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

   2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

   2.2. Level 2:

   2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

   2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

   2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

   2.3. Level 3:

   2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

   2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06

Fleming-Mason Energy measures reliability using the standard indices set forth by the Institute of Electrical and Electronic Engineers (IEEE). These indices include SAIDI, SAIFI, and CAIDI. The measures are made for the system as a whole as wells as by substation and feeder.

The outage information is reviewed monthly by the Fleming-Mason Energy staff to see if there are any trends or problems that may arise. There are plots made for each reliability index and a 12-month moving average is also calculated to identify trends. If necessary, the outage reports will be reviewed to see the cause of any decrease in reliability.

If there is a clear pattern, plans are developed to improve reliability. These plans may involve short-term and long-term solutions to the problems. Short-term solutions may include increased right-of-way clearing, sectionalizing, inspections, or a number of other solutions. Long-term solutions include items typically included in the Construction Work Plan such as reconductoring, pole changes, and the addition of substations.

No. There is no operating range established, but the indices are reviewed for any changes in magnitude or the rolling average.

Refer to answer for question 1.

Momentary outages are excluded because there is still no standard methodology for calculating them. There is still no clear definition for what a momentary outage is or how long the outage should last to be considered a permanent outage.

Major event days are being calculated, but are not used because it is not the method used by the Kentucky Public Service Commission. For yearly indices, we still use the RUS standard of 10 percent of the members out of service for more than 24 hours to define a major storm. Whenever an event meets this criteria, it is excluded from outage statistics.

The following pages are the new RUS outage reporting bulletin that is nearly complete. It follows the standard IEEE indices and makes provisions for major event days in the calculations. This is the guide that Fleming-Mason Energy is currently using.

DRAFT
RUS BULLETIN 161-1

"Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems"

I. PURPOSE AND SCOPE

This bulletin provides guidance on recording and reporting service interruptions/outages, and the calculation of industry standard indices for measuring distribution system performance.

II. DEFINITIONS

AMR (Automated Meter Reading)

Interruption: A loss of electricity for any period longer than 5 minutes.

IEEE: The Institute of Electrical and Electronics Engineers.

IVR: Interactive Voice Response.

Outage: The state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption o fservice to customers, depending on system configuration. This definition does not apply to generation outages.

SAIDI: System Average Interruption Duration Index.

SCADA: Supervisory Control and Data Acquisition.

Power Supply Interruption: Any interruption coming from the transmission system or the substation (even if the distribution system owns the substation or transmission system). If a distribution system owns a sub-transmission system, it and the sub-transmission to distribution substations are considered part of the distribution system. Not included are any substation breakers that go to lockout because of a fault on the distribution system. If there a delivery point is on the distribution system, interruptions caused by something on the source side of the delivery point would be considered a "power supply" outage.

Major Event: This is defined in IEEE Standard 1366-2004 and in Appendix 5 of this document. A major event represents an interruption or group of interruptions caused by conditions that exceed the design and operational limits of the system.

Major Event Day: A day in which the daily SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

Prearranged Interruption: Any interruption scheduled by the distribution system in order for it to safely perform routine maintenance.

All Other Interruptions: All interruptions excluding power supply, major storm, and prearranged.

III. INTERRUPTION REPORTING

A. The Trouble Ticket

The generation of a trouble ticket is the first step in interruption reporting. The first goal of the trouble ticket is to get as much information as possible about the interruption and to pass this information along quickly to the people or systems that need it.

A trouble ticket is traditionally the result of a telephone call from a member reporting a service problem or interruption. These telephone calls have historically been taken by a customer service representative (CSR) using a manual "trouble ticket" form. However, with newer technology, cooperatives can automate this process and render the traditional trouble ticket paperless.

Cooperative personnel should give thought to the process of interruption data-gathering, reporting, and analysis and make a determination of the point at which this data should enter into an electronic format. Because of the flexibility of software systems and the advent of services and products like call centers and interactive voice response systems, the cooperative has many choices to improve its performance in this area.

1. Manual Trouble Ticket

The simplest interruption reporting is the use of a form as shown in Appendix 1. A cooperative employee could fill out this type form manually as they talk to the member on the phone. This same form could be used to dispatch crews and report the cause of the interruption and other pertinent information, making a complete record of the interruption report. It would be used to generate any interruption analysis or reports the cooperative may find useful.

2. Automated Trouble Ticket

Technology available today provides faster response to larger call volumes and allows for interruption data to be quickly assimilated into a computerized outage management system. The result is faster response and restoration times, as well as increased customer satisfaction. There are several methods for generating the automated trouble ticket, including, but not limited to, the use of SCADA, AMR, IVR and call centers. For more discussion on these options, see Appendix 3 on page 17.

B. The Interruption Report

The interruption report is used to document a service interruption. Typically, an interruption report is completed each time a sectionalizing device opens permanently for the purpose of clearing a fault or de-energizing a section of line for construction or maintenance.

The report should provide enough information to comply with RUS and the state's public service commission reporting requirements for service reliability/continuity. Additionally, the form should capture information that will enable the Coop to calculate industry standard reliability indices, as well as to determine the effectiveness of various maintenance activities performed by the Cooperative.

A sample Interruption Report is included in Appendix 2.

C. Reports to RUS

Cooperatives that borrow funds from RUS are required to report the system average annual interruption minutes per consumer on Form 7 and Form 300. Shown below is Part G of Form 7 (Figure 1). The value used in this report is called SAIDI, System Average Interruption Duration Index. It is defined in detail in the Definitions Section of this Bulletin.

Part G. Service Interruptions					
Item	SAIDI (in minutes)				
	Power Supply (a)	Major Event (b)	Planned (c)	All Other (d)	TOTAL (e)
1. Present Year					
2. Five-Year Average					

Figure 1 – RUS Form 7 Part G

Form 7 calls for four separate SAIDIs as well at the total interruption time. The definitions of the terms used in Part G can be found in Part II, "Definitions".

IV. INTERRUPTION ANALYSIS

In addition to RUS reporting requirements, it is recommended that Cooperatives track additional information about service interruptions for more detailed analysis. The purpose of additional analysis is to provide feedback to the Coop's employees, management and board on how well the distribution system is serving the members.

There have traditionally been two codes associated with interruption reporting: cause codes and equipment codes. Every interruption has a cause, but not every interruption results in damaged or failed equipment, such as a recloser properly de-energizing a feeder when contacted by a tree limb. It is important to recognize the distinction between the cause of an interruption other than failed equipment, and a particular piece of equipment that is damaged or needs to be replaced. In the case where no equipment was damaged, the corresponding code in Figure 4, "0999, No Equipment Failure" would be used. Therefore, every interruption will have a cause code and an equipment code associated with it even when no equipment is at fault. Recommended cause codes are shown in Figure 3, and equipment codes are shown in Figure 4.

Weather Condition Codes indicate the conditions that existed when the interruption occurred; it is not to be confused with the cause code that indicates a weather component that might have initiated it. These are shown in Figure 5.

Voltage Level Codes can be used to identify system behavior that is a function of the operating voltage on the damaged components at the time of the interruption. The table in Figure 6 indicates the phase-to-phase voltage level, as some systems operate "Wye" configurations and others operate "Delta" configurations. It is generally accepted that higher voltage systems are more susceptible to lightning damage because of different Basic Insulation Levels (BIL). The cooperative engineer may be able to determine other improvements based on this data as well.

The codes are formatted such that summary and high level reports are easy to produce based on the data in the interruption report. The cooperative may choose to use additional codes for more detailed information and analysis. It is important to note that these tables link together the codes that the cooperative may use, as in the first column, and the codes prescribed by RUS and by IEEE.

Cause Codes			
Coop Code	**RUS FORM 7, Part G, Column**	**IEEE CODE**	**Description**
			Power Supply[1]
000	a	4	Power Supply
			Planned Outage
100	c	3	Construction
110	c	3	Maintenance
190	c	3	Other prearranged

[1] This cause code is used for outages caused by something on equipment not owned by the Distribution Cooperative. If an interruption is caused by something on the cooperative's own transmission system, then a specific cause should be used.

[2] This cause code should only contain those major event days that are determined using the IEEE "Beta Method" described in Part C of this section.

[3] Interruptions marked as "Cause Unknown" should be further investigated to try to determine probable cause.

			Equipment or Installation/Design
300	d	1	Material or Equipment Fault/Failure
310	d	10	Installation Fault
320	d	10	Conductor Sag or Inadequate Clearance
340	d	10	Overload
350	d	10	Miscoordination of Protection Devices
360	d	10	Other Equipment Install/Design
			Maintenance
400	d	1	Decay/Age of Material/Equipment
410	d	1	Corrosion/Abrasion of Material/Equipment
420	d	6	Tree Growth
430	d	6	Tree Failure from Overhang or Dead Tree without ice/snow
440	d	6	Trees with ice/snow
450	d	1	Contamination (Leakage/External)
460	d	1	Moisture
470	d	6	Cooperative Crew Cuts Tree
490	d	10	Maintenance Other
			Weather
500	d	2	Lightning
510	d	7	Wind Not Trees
520	d	7	Ice, Sleet, Frost Not Trees
530	d	7	Flood
590	d	10	Weather Other
			Animals
600	d	8	Small Animal/Bird
610	d	8	Large Animal
620	d	8	Animal Damage – Gnawing or Boring
690	d	8	Animal Other
			Public
700	d	5	Customer-Caused
710	d	5	Motor Vehicle
720	d	5	Aircraft
730	d	5	Fire
740	d	6	Public Cuts Tree
750	d	5	Vandalism
760	d	10	Switching Error or caused by construction/maintenance activities
790	d	10	Public Other
			Other
800	d	10	Other
			Unknown[3]
999	d	9	Cause Unknown

Figure 3 – Cause Codes

Equipment Failure Codes	
Coop Code	**Description**
	Generation or Transmission
010	Generation

020	Towers, poles and fixtures
030	Conductors and devices
040	Transmission substations
090	Generation or Transmission other
	Distribution Substation
100	Power transformer
110	Voltage regulator
120	Lightning arrester
130	Source side fuse
140	Circuit breaker
150	Switch
160	Metering equipment
190	Distribution substation Other
	Poles and Fixtures, Distribution
200	Pole
210	Crossarm or crossarm brace
220	Anchor or guy
290	Poles and Fixtures Other
	Overhead Line Conductors and Devices, Distribution
300	Line Conductor
310	Connector or clamp
320	Splice or deadend
330	Jumper
340	Insulator
350	Lightning arrester line
360	Fuse cutout (damaged, malfunction, maintenance)
370	Recloser or sectionalizer (damaged, malfunction, maintenance)
390	Overhead line conductors and devices, distribution other
	Underground Line Conductors and Devices, Distribution
400	Primary Cable
410	Splice or fitting
420	Switch
430	Elbow arrester
440	Secondary cable or fittings
450	Elbow
460	Pothead or terminator
490	Underground other
	Line Transformer
500	Transfromer bad
510	Transformer fuse or breaker
520	Transformer arrester
590	Line transformer other
	Secondaries and Services
600	Secondary or Service Conductor
610	Metering equipment
620	Security or street light

690	Secondary and service other
	No Equipment Damaged
999	No Equipment Failure

Figure 4 – Equipment or Material Responsible for Interruption

Weather Codes	
010	Rain
020	Lightning
030	Wind
040	Snow
050	Ice
060	Sleet
070	Extreme Cold
080	Extreme Heat
090	Weather Other
100	Clear, calm

Figure 5 – Weather Codes

Voltage Level Codes	
001	< KV(Secondary/Low Voltage)
002	5 KV
003	15 KV
004	25 KV
005	35 KV
006	60 KV
007	> 60 KV

Figure 6 – Voltage Level Codes

A. Use and Analysis of Interruption Data

The time spent collecting the data described above will be wasted unless it is analyzed and the results used as a tool to improve the distribution system performance.

There are many ways the data can be useful. For example, interruption records, which included data on equipment failures, led utilities to discover that two lightning arrester manufacturers had bad batches of arresters which were resulting in premature failures. Another utility used information on lightning damage and location to determine lightning prone areas in their territory. They then selectively improved the grounding only in these areas. This resulted in a least-cost reduction in interruptions due to lightning and also reduced equipment damage.

The goal of all of this is to reduce the number and duration of interruptions. To determine if you are spending your money wisely and truly reducing interruptions, you must keep consistent data over many years to show trends.

B. Definition And Use of the Major Indices

In this section we will discuss the definition of the most significant interruption-related indices and calculations. The following three indices should be calculated:

SAIDI-- System Average Interruption Duration Index
SAIFI-- System Average Interruption Frequency Index
CAIDI-- Customer Average Interruption Duration Index

The IEEE Standard 1366-2004[3] defines SAIDI as the total duration of interruption for the average customer during a predefined period of time (usually one calendar year). It is measured in customer minutes.

$$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Durations (over the period desired)}}{\text{Total Number of Customers Served}}$$

As stated above, SAIDI is usually calculated for a calendar year or "year-to-date", but for major event calculations, **daily** SAIDI values should be recorded. The starting time for the duration of the interruption calculation is determined by the time the cooperative knows about the interruption either by automated means or by the first phone call from the affected area. Interruptions where the customer indicates that the repair can be scheduled for a later date should be counted as an interruption, but with a duration being the estimated amount of time required to repair the problem, including travel time.

The total number of customers served is the average number of customers served over the defined time period. (The sum of the monthly customer count divided by the number of months.) This number should be the same as on the RUS Form 7 except that Public Street and Highway Lighting should not be included. (Security or safety lights, billed to a residential customer, should not be counted on the Form 7)

SAIFI is the number of interruptions that the average customer experiences during the year (or month or day). Interruption recovery time has no effect on this index.

$$\text{SAIFI} = \frac{\text{Total number of customers interrupted}}{\text{Total number of customers served}}$$

CAIDI is the average amount of time that a customer is without power for a typical interruption. It is primarily determined by response time to a reported interruption. However, the number of customers affected by an interruption can affect CAIDI because

[3] Guide for Electric Power Distribution Reliability Indices. IEEE P1366-2004, Copyright © 2003 by the Institute of Electrical and Electronic Engineers, Inc.

the distribution system has limited resources to respond to an interruption that covers an extensive portion of their territory.

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

C. Determination of a Major Event

There are certain things that are beyond the control of the distribution system, primarily natural disasters. Form 7 requires that the SAIDI for these interruptions be reported separately in Part G, Column (b), "Major Event" and not be included in Part G, Column (d), "All Other".

To date there has been no hard and fast rule of what constitutes a major event. It was usually defined as an event that lasted a specified period of time and which caused an interruption for at least a specified number of customers.

For example, an ice storm that results in interruptions of up to ten days and causes an interruption for 80% of customers is clearly a major event. In this case, the interruption records would be kept separately for this event. In calculating the SAIDI for the year, the interruptions from this event should be included in Column b.

What about a severe thunderstorm that caused some customers interruptions of up to 25 hours and where 5% of the customer experience some kind of interruption because of it? Is this a major event or not? Some distribution systems would say yes and others would say no.

It is very desirable to be more consistent across the nation and to take into account the fact that distribution systems with lower SAIDI's should have a lower threshold for what constitutes a "Major Event". The IEEE Working Group on System Design within the Distribution Subcommittee has carefully analyzed the situation and has developed a statistical approach to determine a threshold daily SAIDI level that determines a "Major Event Day". They have defined a major event as a interruption or series of interruptions that exceeds reasonable design and or operational limits of the electric power system. With the issuance of this Bulletin, RUS encourage all cooperatives to start using this approach. All outages that occur during a day determined to be a Major Event Day should be reported in RUS Form 7, Part G, Column (b).

This methodology is fully described in IEEE 1366, "Guide for Electric Power Distribution Reliability Indices" and in Appendix A of this Bulletin. The calculation involves taking the daily SAIDI values for the last five years and taking the natural logarithm of each value in the data set. For those who have an automated system of recording reliability information, this calculation should be easily obtainable. For those who use a manual system, RUS has developed a simple Access Database Form to determine the threshold level for major event days. The form is available to download from the RUS web site http://www.usda.gov/rus/electric/forms/index.htm.

The Interruption Reporting Form (Appendix A) is utilized to calculate the values required on RUS form 7, Part G. No other analysis is performed by this database.

D. Step Restoration Process

When service is restored in several steps, the calculations should be made separately and then added together. The explanation used by the IEEE can be found in appendix 5.

V. SERVICE CONTINUITY OBJECTIVES

A. Demand For Good Service

Rural electric systems now provide power to everything from the peanut farm to the computer network server farm. As utility service entities, cooperatives should strive to provide the level of service needed by the load, consistent with the cost the customer is willing to bear. Approaching reliability from the customer's perspective will help cooperative personnel develop appropriate levels of service for the customer's benefit. A goal may be to improve the CAIDI for a feeder by 20 minutes, or it may be to reach an "Average System Availability Index (ASAI) of "four nines" (99.99%).

In some instances, extreme levels of reliability may be needed which are beyond the cooperative's ability to provide when considering such things as feeder lengths or degree of environmental exposure, frequency of storms, extreme terrain, cost, etc. A joint approach may be used that involves adding facilities on the customer's premises that are owned and maintained by the customer, to achieve these high requirements. The cooperative may agree to meet a minimum reliability number supplemented by customer-owned backup equipment.

RUS guidelines for service reliability should take into consideration those areas that are controllable by the individual borrower and those items that are not. All interruption categories should be analyzed to determine if they are acceptable with regard to customer expectations. The cooperative should look at each category when determining/modifying operating and design practices/criteria. The Power Supplier should be consulted if Power Supply interruptions are excessive. For RUS Form 300, Part II, 7(a), the "All Other" classification will be the primary category for evaluation. The table below shows the current RUS guideline:

Description	All Other SAIDI, In Minutes
Satisfactory (rating of 3)	200 or less
Should Be Explained (rating of 2 or less)	More than 200

B. Establishing Reliability Objectives

When the cooperative sets a goal of reliability, personnel can then take a proactive role in bringing it about through system planning and budgeting. A thorough analysis of interruption causes, number of accounts affected, and durations can tell the engineering and operations staff where to concentrate their efforts. Listed below are several areas to consider for review:

Right-of-Way Clearing	Sectionalizing Scheme
Level of Lightning Protection	Response Time
System Grounding	Personnel Deployment
Pole Treatment/Maintenance	Use of Wildlife Guards
Construction Practices	Loading Levels for Ice and Wind
Level of System Automation	Line Patrolling Activities

By prioritizing likely contributors of interruptions, the engineer is better able to target capital expenditures for the near term to improve the system's overall performance. Long-term benefits of pursuing a continuous improvement in reliability include increased customer satisfaction, lower maintenance expenses, lower demands on operations personnel, better system performance during extreme weather events, and improved safety for lineworkers and the general public. Specific action to be taken by the cooperative to achieve or maintain a satisfactory interruption level should be addressed in the Construction Work Plan.

3. Other Indices

There are several other indices that the cooperative might want to use. Three of these-- SAIFI, SAIDI, and CAIDI-- were discussed above. One other that might be considered is MAIFI (Momentary Average Interruption Frequency Index). This is a measure of the number of breaker operations that do not go to lock-out. This could be used as means to measure system coordination. It might also be used as one measure of the quality of the power supply by recording momentary transmission interruptions.

4. Normalization For Weather

The weather varies across the country. It also varies from year to year. Most thunderstorms are not considered major events but they can have a dramatic effect on the number of customer interruptions throughout the year. By normalizing the interruption data to a "typical" year with regards to lightning, it is possible to see more clearly the condition of the system. A plot of the number of customer interruptions versus the number of cloud-to-ground lightning strikes may illuminate a system's improvement in protection, or decline if arrestors and grounding are not maintained.

Appendix 1

Manual Trouble Ticket

TROUBLE TICKET				
DATE	TIME	RECEIVED BY		
ACCOUNT NO.		REPORTED BY	PHONE NO.	TIME POWER WENT OFF
☐ SERVICE OFF ENTIRELY ☐ NEIGHBORS ALSO OFF ☐ SERVICE DROP DOWN ☐ LIGHTS DIM ☐ CHECKED FUSES		ADDRESS CAUSE LOCATION OF CAUSE		
RECLOSER OR TAP LOCATION		ASSIGNED TO	TIME	TRUCK NO.
ACTION TAKEN				
RESTORED SERVICE TO		TIME	REMARKS	
RESTORED SERVICE TO		TIME		
RESTORED SERVICE TO		TIME		
MATERIAL OR EQUIPMENT; CAUSE OF INTERRUPTION			CODES	
REVIEWED BY				
Dispatcher		Superintendent	Engineer	

Appendix 2

Interruption Report

<table>
<tr><td colspan="4">INTERRUPTION REPORT</td><td colspan="3">REPORT NO.</td></tr>
<tr><td>DATE</td><td>TIME</td><td colspan="5">RECEIVED BY</td></tr>
<tr><td colspan="2">LOCATION OR SWITCH NO.</td><td>REPORTED BY</td><td colspan="2"></td><td colspan="2">TIME POWER WENT OFF</td></tr>
<tr><td>SUBSTATION</td><td></td><td colspan="5"></td></tr>
<tr><td>FEEDER</td><td></td><td colspan="5">CAUSE</td></tr>
<tr><td>DISTRICT</td><td></td><td colspan="5">LOCATION OF CAUSE</td></tr>
<tr><td colspan="2"></td><td colspan="2">ASSIGNED TO</td><td>TIME</td><td colspan="2">TRUCK NO.</td></tr>
<tr><td colspan="7">ACTION TAKEN</td></tr>
<tr><td>RESTORED SERVICE TO</td><td>DATE</td><td>TIME</td><td colspan="2">NO. CUSTOMERS</td><td colspan="2">CUSTOMER-MINUTES</td></tr>
<tr><td>RESTORED SERVICE TO</td><td>DATE</td><td>TIME</td><td colspan="2">NO. CUSTOMERS</td><td colspan="2">CUSTOMER-MINUTES</td></tr>
<tr><td>RESTORED SERVICE TO</td><td>DATE</td><td>TIME</td><td colspan="2">NO. CUSTOMERS</td><td colspan="2">CUSTOMER-MINUTES</td></tr>
<tr><td></td><td colspan="2"></td><td colspan="2">TOTAL CUSTOMERS</td><td colspan="2">TOTAL CUSTOMER-MINUTES</td></tr>
<tr><td colspan="3" rowspan="3">MATERIAL OR EQUIPMENT</td><td colspan="4">CODES</td></tr>
<tr><td>CAUSE</td><td>EQUIP</td><td>WEATHER</td><td>RUS FORM 7</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="7">REVIEWED BY

Dispatcher   Superintendent   Engineer</td></tr>
</table>

Appendix 3

Call Centers, SCADA, and IVR

Call Center

Call Centers have grown out of a need by cooperatives to handle larger call volumes with a person rather than a machine. The call center can either be staffed in-house by cooperative employees or outsourced to a call center at a different location. Due to economics or the desire to have high volume call handling capabilities with live customer service representatives outsourcing may be the way to go for many cooperatives. In either case, the customer service representative will talk to the member gathering information needed to identify the member and the location of the interruption, including any other information the member may have about the interruption. The customer service representative may also be able to share information about the interruption with the member if they are already aware of the interruption. Call centers could then electronically forward this information to the appropriate operating personnel for dispatching and service restoration or as input to an interruption management system. In some cases, if properly equipped, the call center may actually dispatch the trouble ticket to the crew doing restoration.

Successful operation of a call center involves being sure the customer service representatives are trained to provide a positive image of the cooperative. The member should not be able to tell if the customer service representative (CSR) is a cooperative employee or an employee of an outsource call center. These CSRs should have fast reliable access to a customer database that will quickly provide account location and status (i.e., off for non-payment). This database should be updated at least daily. Theses CSRs should also have access to information concerning status of interruptions so they can keep members informed as the interruption progresses.

Interactive Voice Response Systems (IVR)

If a cooperative is willing to use advance call answering technologies they may want to investigate the use of an IVR system. These systems use electronic voice messaging to handle large call volumes fast and efficiently. These systems are especially attractive if the cooperative is using an automated interruption management system. Again, as in the call center application, these systems can either be implemented in-house or outsourced to third party vendors. Often this decision is based on a cooperative's ability to size their incoming phone lines to handle the phone traffic needed on large interruptions. For example, the existing cooperative capability may be only 12 – 24 incoming lines, while third party facilities may be capable of over 500 incoming lines. This increased call handling capability is especially critical if the cooperative is using an automated interruption management system. The cooperative may also consider using an emergency overload system where the calls go to the third party only after a set call volume is reached.

An IVR system works very similar to a call center except the customer is talking to a machine and not a live person. However, with advance speech recognition systems becoming more common, these systems are becoming more and more member friendly.

IVR systems require access to a current customer database giving account location and status (i.e. off for non-payment). Most IVR systems use member phone numbers for account recognition. This can be done using caller ID systems or by the member entering their phone number in response to a request from the IVR. Using phone numbers as account recognition requires cooperatives to be diligent in keeping phone numbers current for all accounts and in the case of multiple accounts the IVR system must have a method of distinguishing which account is actually out. This can be done by the IVR using text messaging of some account location field, which would uniquely identify the location to the member; or the IVR, using speech recognition, could ask the member to leave a message describing the proper location. If both of these methods failed the IVR could simply forward the member to a live person for resolution.

IVR systems also have the ability, when tied to an interruption management system, to give members feedback on interruption status and restoration time.

Appendix 4

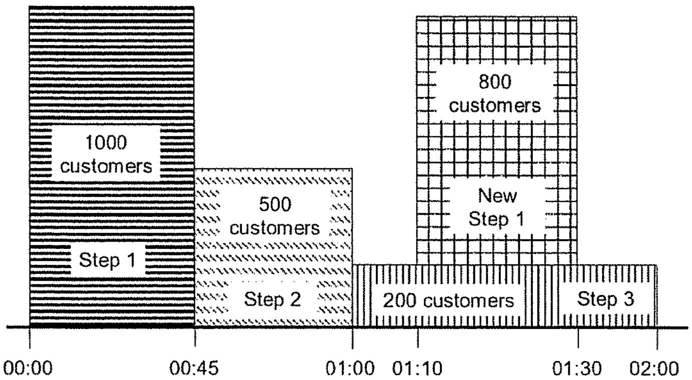
The Step Restoration Process and Example

The following case illustrates the step restoration process. A feeder serving 1,000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. The table shows the times of each step, a description and associated customer interruptions and minutes they were affected in a time line format.

Relative Time	Description	Customers	Duration (Minutes)	Customer-minutes of Interruption
00:00	1,000 customers interrupted.			
00:45	500 customers restored; 500 customers still out of service.	500	45	22,500
1:00	Additional 300 customers restored; 200 customers still out of service.	300	60	18,000
1:10	Feeder trips again, 800 previously restored customers interrupted again. (200 remained out and were not restored at this time.)			
1:30	800 customers restored again.	800	20	16,000
2:00	Final 200 customers restored. Event ends.	200	120	24,000
Totals:		1,800		80,500

Example SAIFI = 1,800/1,000 = 1.8 interruptions
Example CAIDI = 80,500/1,800 = 44.7 minutes
Example SAIDI = 80,500/1,000 = 80.5 minutes

The graph below shows the steps as they happened:



Appendix 5

Calculation of Major Event Days

The following process ("Beta Method") is used to identify major event days (MEDs). Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. This approach supercedes previous major event definitions.

A major event day is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the major event days, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period as follows:

1. Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical date are available, use all available historical data until five years of historical data are available.
2. Only those days that have a positive SAIDI/Day value will be used to calculate the T_{MED}. Exclude the days that have no interruptions.
3. Take the natural logarithm, (ln) of each daily SAIDI value in the data set.

4. Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
5. Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
6. Compute the major event day threshold, T_{MED}, using the equation below.

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

7. Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a major event day.

Formal procedures are not documented, but line technicians are to follow all safety procedures as outlined in the APPA safety manual that is adopted at Fleming-Mason Energy.

a. Yes. This is the type of clearing that is used on the distribution system. The only exception is when there are shade trees in a residential member's yard. If this tree will cause reliability issues, we will either perform directional pruning or work with the member to remove the tree. Other than that exception, Fleming-Mason Energy works very hard to maintain right-of-way as described in the RUS guide.

b. N/A

a. Fleming-Mason Energy is an RUS borrower; therefore, we prefer the method that is described by RUS. The NERC guide is not as easily adaptable to distribution systems as the RUS method and a level of complexity is added to distribution reporting that is necessary for the transmission clearing practices but not for distribution.

b. Many of the requirements in R3 are currently being met. They include tracking of tree-related outages and the ability to track information about each outage including date, time, circuit, and duration. However, at this point, we are not categorizing tree-related outages by the method described in R3.4. We consider a tree-related outage as one that is caused by a tree regardless of proximity to the right-of-way.

c. There were 97 confirmed outages related to vegetation for 2006.

As stated in question 8, the preferred standard would be the RUS standard. The only addition to this would be that the ANSI standards for trimming and clearance of trees be considered as the appropriate method.