A Touchstone Energy® Cooperative

# Public Service Commission

# Administrative Case No. 2006-00494

# Second Data Request of Commission Staff

Prepared by
NOLIN RURAL ELECTRIC COOPERATIVE CORPORATION
&
ENVISION ENERGY SERVICES
Roger Wilson, PE

February 19, 2007

A Touchstone Energy Cooperative

RECEIVED

FEB 22 2007

PUBLIC SERVICE
COMMISSION

February 21,2007

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

RE: **Administrative Case No. 2006-0094**
Second Data Request of Commission Staff To
Jurisdictional Electric Distribution Utilities

Dear Ms. O'Donnell:

Please find enclosed the original and six (6) copies of the responses to the "Second Data Request of Commission Staff To Jurisdictional Electric Distribution Utilities."

If you have any questions on the content of the responses please contact Vince Heuser, Vice President of System Operations at the Nolin Rural Electric Cooperative Corporation office in Elizabethtown, KY [270-765-6153].

Sincerely,

Roger Wilson

Roger Wilson, PE

411 Ring Road
Elizabethtown, KY 42701-6767

A Touchstone Energy Cooperative



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Second Data Request on Case No. 2006-00494



Vince Heuser will answer related questions to these responses.
[Phone (270)765-6153]

1. Nolin RECC in the past has maintained a detailed monthly outage data from paper outage tickets. The outage tickets were sorted as to cause, length of time, number of consumers, and line section number. The monthly details were compiled for annual reports that are required by Rural Utilities Services (RUS). The substation circuit reclosers' operation counters are also used in the defining of feeders that may have shown excessive number of counts. These two items were the only confirming means of identifying problem areas by historical data. The annual report system was confirming method of identifying abnormally fast growing tree areas [outside of the normal right of way cycle] and equipment upgrades due to age or storm damage. With the advent of the advanced Turtle AMR equipment monitoring, the system can be analyzed more precisely. This gives Nolin RECC staff more accurate record keeping, as well as maintaining faster response to its consumers.

Vince Heuser will answer related questions.

2. Nolin RECC strives to provide the best service possible to the consumer. Nolin's overall system stands above the normal standards of SAIFI, SAIDI, and other bench marking performance indices established in Institute of Electrical and Electronics Engineers (IEEE) and Electric Power Research Institute (EPRI). The performance standards are taken into account in planning, but the major goal is to improve our existing numbers to a higher threshold.

Vince Heuser will answer related questions.

3. Nolin RECC uses RUS procedures and outlines to formulate a work plan for annual system improvement circuits. The form 300 is a developmental tool for the inclusion of reliability into the work plan's projects and is required at least every other work plan. The form and explanation for items in document may be found in the RUS Bulletin 1730.1 [***Exhibit A***]. The Form 300 is used in conjunction with outage data locations, load data and other historical data for the justification to improve a lines operation for a given area. Milsoft Engineering package is used to complete the planning and analysis of the system circuits with load data, voltage drop, and fault current studies. These studies and the related outage information are the determining factors of additional maintenance or system upgrade.

Vince Heuser will answer related questions.

4. Momentary interruptions are very difficult to capture, but with the Turtle AMR, the information will be more readily accessible. Many customers often seem more concerned about momentary interruptions than sustained interruptions. Measuring momentary reliability requires an enhanced focus and more extensive data gathering for the development of meaningful reliability indices. The gathering and accurately translating of this data can be extremely difficult to capture and expensive to the consumer. The interpretation, once the data has been assembled, is very time consuming and proves to add even more cost.

Vince Heuser will answer related questions.

5. The major events and storms should not be excluded completely from the system study, for there is value in the data. Major events and storms can actually skew a final system wide solution, if they are kept in the calculation. The storm outage takes place at one time in one region. To concentrate the system's over-all resources to an area based on one event could center funds in an area that is not needed, and leaving other regions under funded. The overall system outages should be looked at as a normally operated condition to provide a better plan for all consumers. Then consideration for the major events can be evaluated as a part of the systems overall plan.

Vince Heuser will answer related questions.

6. The RUS covers the reliability reporting by:

    a. DRAFT, RUS BULLETIN 161-1, "Interruption Reporting and Service Continuity Objectives for Electric Distribution System".[***Exhibit B***]
    b. RUS Guide "Guide for the Development of Reliability Indices for Benchmarking". [***Exhibit C***]

Vince Heuser will answer related questions.

7. The general plan that is followed during major storm outages is:

    a. Identifying the major outage areas.
    b. Identifying public safety concerns, medical emergency consumers, potable water consumers, and waste treatment consumers.
    c. Restoring service to substations and sources.
    d. Restoring service to main three phase feeders.
    e. Restoring service to secondary three phase feeders.
    f. Restoring service to single phase taps.
    g. Restoring service to individuals.

   These steps may vary with the location and severity of the event.

Vince Heuser will answer related questions.

8. a). Nolin RECC does follow this guide line, with exceptions:

   a. Where narrow profile fiberglass arms are used.
   b. Spacer Cable or tree wire is strung.
   c. Locations of environmentally sensitive areas.
   d. Locations of shade trees where consumer is undeviating to trimming.

8. b). No answer required.

Vince Heuser will answer related questions.

9. a). Preferred M1.30G-The Voltage levels in most distribution systems are not as variable as transmission, therefore leaving a much less variation of right of way widths. The simpler form is easier for consumers to understand and accept during periods of negotiating through a property owner.
9. b). Nolin RECC would be able to have a person report events. The events would be exceptionally small quantity and very few consumer numbers, in comparison to transmission scale, which NERC originally developed RROs. The benefit of data would be limited to a comparison between distribution systems, with no real base line. The distribution systems topography, consumer base structure, and climate characteristics will vary widely, rendering little to no value in comparison of data complied. The NERC form proposal of distribution data in outages could be used in improving the numbers within the system rather than comparison to a group of unlike systems.
9. c). With the criterion of the categories set up for transmission, it makes data gathering of accurate results questionable. We show tree caused outages to be 21 tree events, all or some of which, may not be a reportable event according to rule R3.2.

Vince Heuser will answer related questions.

10. Nolin RECC has always placed a high standard of service for our consumers. The advent of the Turtle AMR will be a more precise measuring device to give a true picture of that service. The present IEEE and EPRI standards are relative to residential for the most part. In the case of industry or commercial setting it could pose to be below par. Without a much improved data base for the real world standard, by way of the new AMRs in the industry, it would be best to stay with the existing standard.

Vince Heuser will answer related questions.

36. All of Nolin RECC's substations are equipped with SCADA.

Vince Heuser will answer related questions.

37. There are no reclosers down line of the substation's breakers equipped with SCADA.

Vince Heuser will answer related questions.

38. The Nolin RECC's SCADA has incorporated the Hunt Technologies TS2 meters. They use the endpoints as Always On™, providing continuous monitoring 24 hours per day of every meter. The Nolin Dispatch Center monitors the SCADA and the Turtle equipment in the home office. The Dispatch Center uses the TS2 meters to assist in locating trouble areas and dispatching crews. The meter points are also used in the restoration process to make sure all consumers are back on. In addition, a special meter is placed at the end point of each feeder to record voltage data for highs and lows and is for quality monitoring. The recorded data sent to the Dispatch Center is time stamped for accurate and reliable analyze. (The following web pages will give details of the Turtles capabilities.

    a. http://www.hunttechnologies.com/outage.asp
    b. http://www.hunttechnologies.com/pdf/TS1FocusEndpt_08_25.pdf

Vince Heuser will answer related questions.

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

**Bulletin 1730-1**

**SUBJECT:** **Electric System Operation and Maintenance (O&M)**

**To:** RUS Electric Borrowers and RUS Electric Staff

**Effective Date:** Date of Approval

**Expiration Date:** Seven Years from Effective Date

**Office of Primary Interest:** Electric Staff Division

**Filing Instructions:** This Bulletin supersedes REA Bulletin 161-5, Electric System Review and Evaluation, dated October, 1978. File this bulletin with 7 CFR 1730.

**Purpose:** This bulletin contains guidelines related to electric borrowers' operation and maintenance (O&M) and outlines the Rural Utilities Service's (RUS) standard practices with respect to review and evaluation of O&M practices.

/s/
Assistant Administrator - Electric Program

January 1/26/98
Date

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## ABBREVIATIONS

| | |
|---|---|
| **ANSI** | American National Standards Institute |
| **CAP** | Corrective Action Plan |
| **CFR** | Code of Federal Regulations |
| **CT** | Current Transformer |
| **EMF** | Electric and Magnetic Fields |
| **EPA** | Environmental Protection Agency |
| **GFR** | General Field Representative |
| **IFT** | Interfacial Tension |
| **kVA** | Kilovolt-Ampere |
| **kW** | Kilowatt |
| **kWh** | kilowatt-hour |
| **NESC** | National Electrical Safety Code |
| **O&M** | Operations and Maintenance |
| **OCR** | Oil Circuit Recloser |
| **PCB** | Polychlorinated Biphenyl |
| **PSD** | Power Supply Division |
| **PT** | Potential Transformer |
| **REA** | Rural Electrification Administration |
| **RUS** | Rural Utilities Service |

**1. Purpose:** This bulletin contains guidelines related to electric borrowers' operation and maintenance (O&M) and outlines the Rural Utilities Service's (RUS) standard practices with respect to review and evaluation of O&M practices. 7 CFR 1730 contains the policies and procedures of RUS related to electric borrowers' O&M practices and RUS' review and evaluation thereof.

## 2. Borrower Guidelines

**2.1 Records:** Each borrower is responsible for maintaining records of the physical and electrical condition of its electric system. Any or all of these records may be reviewed by RUS during its review and evaluation. Such records include, but are not limited to:

(a) Service interruption reports and summaries of experience (including power supply outages.)

(b) Overhead and underground line inspection and maintenance records, including pole inspection and line patrol records.

(c) Substation inspection and maintenance records.

(d) Recloser and sectionalizer records.

(e) Line Voltage regulator records.

(f) Distribution transformer records.

(g) Watt-hour and demand meter records.

(h) Right-of-way maintenance records.

(i) Line Voltage and current records.

(j) Up-to-date system maps.

(k) System losses.

(l) Idle services.

(m) External system impacts (including EMF questions, stray voltage, radio and television interference, etc.)--records of inquiries and resulting actions.

**2.2 Emergency Restoration Plan:** Each borrower should have a written plan detailing how to restore its system in the event of a system wide outage resulting from a major natural disaster or other causes. This plan should include how to contact emergency agencies, borrower management and other key personnel, contractors and equipment suppliers, other utilities, and any others that might need to be reached in an emergency. It should also include recovery from loss of power to the headquarters, key offices, and/or operation center facilities. It should be readily accessible at all times under any and all circumstances.

**2.3 System Ratings:** RUS Form 300, Review Rating Summary, includes a numerical rating system as follows:

0: Unsatisfactory - no records
1: Unsatisfactory - corrective action needed
2: Acceptable, but could be improved - see attached recommendations
3: Satisfactory - no additional action required at this time
N/A: Not applicable

Exhibit A provides a guide for the conditions normally needed to justify a rating of 3 for each of the items on RUS Form 300. The explanatory notes section of RUS Form 300 should include a list of all items rated as unsatisfactory (ratings 0 or 1) along with comments indicating the action or implementation that is proposed. This is in addition to the corrective action plan (CAP) required by 7 CFR 1730. Additional expenditures required for deferred maintenance should be indicated in the O&M Budgets, Part IV of RUS Form 300. These may be distributed over a period of 2 or 3 years as indicated on the form.

## 3. Review and Evaluation of O&M Practices by RUS

**3.1.** RUS will conduct a periodic review and evaluation of each borrower's operation and maintenance programs and practices. The purpose of this review is to assess loan security and to determine borrower compliance with RUS policy as outlined in part 7 CFR 1730.

**3.2. Distribution Borrowers:** The General Field Representative (GFR) is responsible, within the GFR's assigned territory, for initiating and conducting a periodic review and evaluation of each distribution borrower's operation and maintenance programs, practices, and records. This review and evaluation is to be done at least once every 3 years.

**3.2.1** The GFR may inspect facilities as well as records, and may also observe construction and maintenance work in the field. Key borrower personnel responsible for the facilities being inspected should accompany the GFR during such inspections.

**3.2.2** If adequate information is available, the GFR will complete the review and evaluation and consult with the borrower regarding its programs and records for operation, maintenance, and system improvements. The GFR's signature on the Form 300 signifies concurrence with the borrower's analysis, ratings, and explanatory notes unless indicated otherwise.

**3.2.3** If adequate information is not available, the GFR's review and evaluation will be deferred until the borrower has remedied the deficiencies identified by the GFR.

**3.2.4** Upon completion of the O&M review and evaluation, the GFR will communicate his/her findings to the borrower.

**3.3 Power Supply Borrowers:** The Power Supply Division (PSD) is responsible for initiating and conducting a periodic review and evaluation of each power supply borrower's operation and maintenance programs, practices, and records . PSD will consult with the borrower and arrange a scheduled time for the review and evaluation. PSD will determine the frequency of this review and evaluation.

**3.3.1** The GFR will, upon request by PSD, assist in the review and evaluation, particularly with respect to transmission, subtransmission, and substation facilities.

# EXHIBIT A

# RUS FORM 300 RATING GUIDE

# CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

## PART I - TRANSMISSION and DISTRIBUTION FACILITIES

### 1. Substations (Transmission and Distribution)

a. Safety, Clearance, Code Compliance: No violations of RUS or NESC requirements including clearance or separations in any substation. All substations accessible by authorized personnel only. Operating manual available for each substation.

b. Physical Condition: Structure, Major Equipment, Appearance: Rare instances of rust, weeds, dangerous insects, and bird nesting. No leaks, no temporary bus being used on an ongoing basis, only minor material associated with maintenance of the substation equipment stored in yard. No debris, no openings under fence greater than 3 inches (76 mm), no broken insulators, parallel power transformers properly fault protected. Circuit, phases & airbreak switch handles are properly identified.

c. Inspection Records Each Substation: Written monthly inspection reports completed and reviewed by responsible personnel for all substations. Infrared inspection of all connectors at least every five years. Dielectric, dissolved gas, and interfacial tension (IFT) tests of oil filled equipment performed at least every five years or within one year of exposure to a through fault which causes the transformer protective devices to de-energize the transformer. Annual power factor test of all equipment rated 230 kV or above. Relays are functionally tested annually and cleaned, calibrated, and tested every three years.

d. Oil Spill Prevention: Oil spill prevention and mitigation plans prepared and available for all substations.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

**2. Transmission Lines**

a. Right-of-Way - Clearing, Erosion, Appearance, Intrusions: No uncontrolled erosion. Gates or gaps at all fence crossings. Structures and lines not impacted by untrimmed right of way. Structures generally accessible by service vehicles.

b. Physical Condition - Structure, Conductor, Guying: All structures vertical and guys taut. No broken insulators or crossarms, and no unauthorized attachments. Essentially all structures numbered. Structures and attachments conform to NESC requirements.

c. Inspection Program and Records: Walking, riding, or aerial line patrol of all lines (including those on private right-of-way) performed at least annually. Records maintained for pole inspection and line patrol and deficiencies corrected on a timely basis. Above and below ground pole inspection performed on cycle based upon decay zone using experienced inspectors.

**3. Distribution Lines - Overhead**

a. Inspection and Maintenance - Program and Records: Above and below ground pole inspection performed on cycle based upon decay zone using experienced inspectors. Records of all poles inspected, treated, rejected and changed out readily available in summary form. All overhead lines (including those on private right-of-way) patrolled annually (walking, riding, or aerial); more frequently if experience dictates. Records maintained for pole inspection and line patrol with deficiencies corrected in a timely manner. Pole and equipment changeout program in place to keep rejected poles and failed equipment to a minimum.

b. Compliance with Safety Codes - Clearances: All facilities staked prior to construction by personnel familiar with NESC requirements. Line patrols identify changed conditions requiring greater clearances.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

Compliance with Safety Codes - Foreign Structures: Utility has policy and practice of immediately remedying foreign structures which conflict with primary lines upon observation.

Compliance with Safety Codes - Attachments: All overhead attachments meet NESC separation and clearance requirements. Up-to-date joint-use and pole rental agreements are in effect. Unauthorized attachments and violations of the NESC promptly remedied.

c. Observed Physical Condition from Field Checking - Right-of-way: Structures and lines not impacted by untrimmed right-of-way. Right-of-way re-trimming cycles to be dictated by local conditions.

   Observed Physical Condition from Field Checking - Other: Rare instances of leaning poles, slack guys, broken grounds, loose hardware and superfluous material on structures. No broken crossarms or insulators, and no pole steps on wood poles. Installation of miscellaneous distribution equipment meets NESC requirements. Neutral properly identified when located on crossarm.

**4. Distribution - Underground Cable**

a. Grounding and Corrosion Control: Ground rods located at each transformer plus at least four per mile (1.6 km), not including grounds at individual services, in accordance with the NESC. Record system kept of visible cable condition when excavated. Periodic testing at selected locations of underground cable and grounding points for evidence of corrosion. Appropriate and timely actions taken to correct any unsatisfactory conditions.

b. Surface Grading, Appearance: Rare instances of earth settling which could create hazards to the general public and timely action taken to correct any deficiency.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

c. Riser Poles: Hazards, Guying, Condition: Cut-outs mounted per RUS requirements. Riser cable covered with conduit to within 4 feet (1.2m) of the bottom of the potheads. Adequate surge protection installed.

**5. Distribution Line Equipment: Conditions and Records**

a. Voltage Regulators: Voltage regulators inspected and maintained in accordance with the manufacturer's recommended timetable. Regulators checked for proper operation at least semi-annually. Knowledge of and compliance with EPA requirements with respect to PCB contaminated oil and equipment. Dielectric, dissolved gas, and IFT tests of oil filled equipment performed every five years or within one year of exposure to a through fault which causes the protective devices to de-energize the regulator.

b. Sectionalizing Equipment: Oil circuit reclosers (OCR's) and breakers inspected and maintained in accordance with the manufacturer's recommended timetable. Records reflect inspection results, maintenance performed, and date.

c. Distribution Transformers: Complete records kept as to size, location, and date installed. Knowledge of and compliance with EPA requirements with respect to PCB contaminated oil and equipment. Transformer loading analysis performed periodically as needed.

d. Pad Mounted Equipment - Safety - Locking, Dead Front, Barriers: All padmount enclosures meet RUS dead-front requirements (secondary barriers, recessed penta-head nut, and separate pad-lock.) Grounding in accordance with RUS and NESC requirements. "Danger" signs inside all enclosures and "Warning" signs on the exterior in accordance with ANSI Z535.

Pad Mounted Equipment - Appearance - Settlement, Condition: Rare instances of leaning or undermined enclosures. Prompt action taken to correct deficiencies.

# CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

e. Watt-hour and Demand Meter Reading and Testing: All meters tested in accordance with state regulations (where applicable) or ANSI C12.1. PT, CT and demand meters are generally tested on at least a 3 year cycle. Complete records kept as to size, location, and date installed.

## PART II - OPERATION AND MAINTENANCE

### 6. Line Maintenance and Work Order Procedures

a. Work Planning and Scheduling: All lines staked prior to construction by personnel familiar with NESC requirements. Work order inspections performed in accordance with 7 CFR 1724, Electric Engineering, Architectural Services and Design Policies and Procedures (i.e., within 6 months of completion of construction.) Utility promptly provides inspector with written notice that clean-up work has been completed. Construction Work Plan projects completed in time to meet load level requirements. New service connections completed in reasonable time frames.

Work Backlogs - Right-of-way Maintenance: Adequate resources being provided to address re-clearing on timely basis. Right-of-way re-trimming cycles to be dictated by local conditions.

Work Backlogs - Poles: All reject poles replaced within 6 months of inspection. "Danger" and "Hazard" poles replaced as soon as possible.

Work Backlogs - Idle Services - Retirement of: Policy and procedures in place to address retirement of idle services so that ratio of idle services to total is less than 10% unless specific local conditions dictate otherwise.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

Work Backlogs - Other: Job orders from line inspection completed in reasonable time frames.

**7. Service Interruptions**

a. Average Annual Hours/Consumer by Cause: Rating to consider the effect of all types of outages, including planned. Evidence of concern would be when total outages exceed 5 hours or power supply outages exceed 1 hour per consumer per year. Outages accounted for in accordance with RUS Bulletin 161-1.

b. Emergency Restoration Plan: Emergency restoration plan readily available and covers multiple scenarios, including loss of power to the headquarters, key offices, and/or operations centers.

**8. Power Quality**

General Freedom from Complaints: Minimal complaints with respect to television and radio interference, voltage flicker, neutral-to-earth voltage, harmonics, and EMF. Complaints generally resolved quickly and effectively. Summary of complaints maintained and analyzed periodically.

**9. Loading and Load Balance**

a. Distribution Transformer Loading: Loading ratio (kVA to peak kW) may range from 2 to 4, depending upon levels of load management, seasonal customers, as well as other factors.

b. Load Control Apparatus: Have records of individual controllers showing location, type of load being controlled, and any maintenance. Load control results summarized.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

c. Substation and Feeder Loading: All feeders balanced at each substation to within 20% during peak loads.

**10. Maps and Plant Records**

a. Operating Maps - Accurate and Up-to-Date: Consumers can be identified by location with a set of maps carried by all service personnel. Maps depict roads, grid lines, waterways, railroads, and other landmarks necessary to locate consumers. Maps are of a functional size and permit location of consumers irrespective of date of service. Detail maps are current and up to date, generally 1 year old or less.

b. Circuit Diagrams: Current and up-to-date map (generally 2 years old or less) depicting a multiple line layout of distribution facilities of the utility. The location and sizes of substations, line regulators, reclosers, capacitors, and substation boundaries are clearly shown. Primary voltage drops are indicated at the ends of primary feeder lines. All transmission lines are located and identified as to voltage and ownership.

d. Staking Sheets: Staking sheets are prepared for projects prior to construction. The sketch and construction units are consistent. North arrow and grid reference are present. Spans lengths are correctly listed and all line angles and guy lead lengths are stated. Final staking sheets are consistent with the "as-built" conditions.

**PART III - ENGINEERING**

**11. System Load Conditions and Losses**

a. Annual System Losses: System losses are appropriate for the conditions encountered. Reasonable efforts made to reduce system losses.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

b. Annual Load Factor: Load factor is appropriate for the conditions encountered, generally at least 45%. Reasonable efforts made to improve load factor, where possible.

c. Power Factor at Monthly Peak: Each distribution substation maintains a power factor between 0.95 lagging and 0.95 leading at time of power supply coincident peak demand.

**12. Voltage Conditions**

a. Voltage Surveys: Sufficient number of recording and/or indicating voltmeters are available and utilized to monitor specific locations where voltage conditions warrant special attention. Annual graphs or statistical analyses are kept for each meter for the most recent 5 year period.

b. Substation Transformer Output Voltage Spread: All substations include automatic voltage regulators or voltage regulating transformers. Each substation has continuous voltage recording which is monitored monthly by computer analysis. Regulated substation output voltage and line regulators are maintained so that Range A service voltage per RUS Bulletin 169-4 is provided to all consumers.

**13. Load Studies and Planning**

a. Long Range Engineering Plan: System planning study is current, meets the requirements of 7 CFR 1710, can be used as a guide for preparing the next Construction Work Plan, and is prepared in accordance with RUS Bulletin 1724D-101A.

b. Construction Work Plan: Work Plan is up-to-date, meets the requirements of 7 CFR 1710, and is prepared in accordance with RUS Bulletin 1724D-101B.

c. Sectionalizing Study: System sectionalizing is reviewed and updated as needed concurrently with each Construction Work Plan and with significant change in fault current conditions.

## CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

d. Load Data for Engineering Studies: A completely integrated data base automatically assigns consumers, and their load (kWh or kW) to specific geographical locations that are associated with specific distribution line sections. Data is sufficiently accurate that the difference between the calculated and measured substation kW is less than 5%.

e. Power Requirements Data: Power requirements study is current and completed in compliance with the requirements stated in 7 CFR 1710.

### PART IV - OPERATION AND MAINTENANCE BUDGETS

### 14. Budgeting

Adequacy of Budgets For Needed Work: Utility prepares an annual budget with specific item quantities and dollars prior to the beginning of each year for each department. The O&M budget is broken down to show each program, the quantities of work to be accomplished and the timing during the year when the proposed work is to be performed.

# 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

<table>
<tr><td colspan="5">TROUBLE TICKET</td><td colspan="4"></td></tr>
<tr><td>DATE</td><td>TIME</td><td colspan="7">RECEIVED BY</td></tr>
<tr><td colspan="2">ACCOUNT NO.</td><td colspan="2">REPORTED BY</td><td colspan="3">PHONE NO.</td><td colspan="2">TIME POWER WENT OFF</td></tr>
<tr><td colspan="2" rowspan="3">☐ SERVICE OFF ENTIRELY<br>☐ NEIGHBORS ALSO OFF<br>☐ SERVICE DROP DOWN<br>☐ LIGHTS DIM<br>☐ CHECKED FUSES</td><td colspan="7">ADDRESS</td></tr>
<tr><td colspan="7">CAUSE</td></tr>
<tr><td colspan="7">LOCATION OF CAUSE</td></tr>
<tr><td colspan="2">RECLOSER OR TAP LOCATION</td><td colspan="3">ASSIGNED TO</td><td colspan="2">TIME</td><td colspan="2">TRUCK NO.</td></tr>
<tr><td colspan="9">ACTION TAKEN</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td colspan="3">TIME</td><td colspan="3" rowspan="3">REMARKS</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td colspan="3">TIME</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td colspan="3">TIME</td></tr>
<tr><td colspan="7" rowspan="2">MATERIAL OR EQUIPMENT; CAUSE OF INTERRUPTION</td><td colspan="2">CODES</td></tr>
<tr><td></td><td></td></tr>
<tr><td colspan="9">REVIEWED BY<br><br>Dispatcher      Superintendent      Engineer</td></tr>
</table>

# Appendix 2

# Interruption Report

| INTERRUPTION REPORT | | | REPORT NO. |
|---|---|---|---|
| DATE | TIME | RECEIVED BY | |
| LOCATION OR SWITCH NO. | | REPORTED BY | TIME POWER WENT OFF |
| SUBSTATION | | | |
| FEEDER | | CAUSE | |
| DISTRICT | | LOCATION OF CAUSE | |
| | ASSIGNED TO | TIME | TRUCK NO. |
| ACTION TAKEN | | | |

| | | | | |
|---|---|---|---|---|
| RESTORED SERVICE TO | DATE | TIME | NO. CUSTOMERS | CUSTOMER-MINUTES |
| RESTORED SERVICE TO | DATE | TIME | NO. CUSTOMERS | CUSTOMER-MINUTES |
| RESTORED SERVICE TO | DATE | TIME | NO. CUSTOMERS | CUSTOMER-MINUTES |
| | | | TOTAL CUSTOMERS | TOTAL CUSTOMER-MINUTES |

| MATERIAL OR EQUIPMENT | CODES | | | |
|---|---|---|---|---|
| | CAUSE | EQUIP | WEATHER | RUS FORM 7 |
| | | | | |

| REVIEWED BY | | |
|---|---|---|
| Dispatcher | Superintendent | Engineer |

# 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

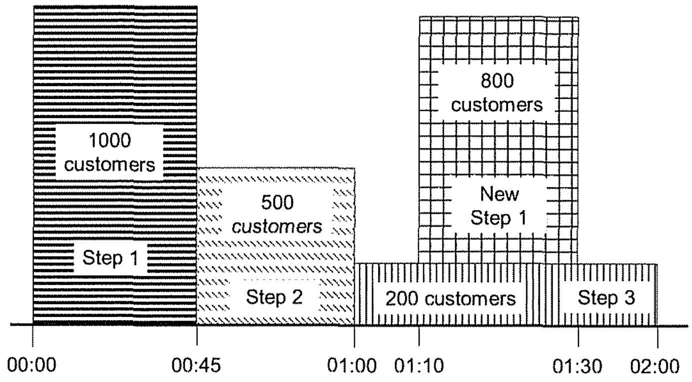
## The Step Restoration Process and Example

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;<br>500 customers still out of service. | 500 | 45 | 22,500 |
| 1:00 | Additional 300 customers restored;<br>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.<br>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.

**UNITED STATES DEPARTMENT OF AGRICULTURE**
**Rural Utilities Service**

RUS Guide

**SUBJECT:** Guide for the Development of Reliability Indices for Benchmarking the Transmission and Distribution Substation Components of the Delivery System

**TO:** RUS Electric Borrowers and RUS Electric Staff

**EFFECTIVE DATE:** Date of Approval.

**OFFICE OF PRIMARY INTEREST:**

**PREVIOUS INSTRUCTION:** None.

**FILING INSTRUCTION:** None.

**AVAILABILITY:**
This guide is available to RUS staff on RUSNET and can be viewed and downloaded by borrowers and all others connected to the Internet at:

http://www.usda.gov/rus/home/home.htm

**PURPOSE:** To provide the Rural Utilities Service (RUS) borrowers and others guidance on the development of reliability indices that may be used for benchmarking the performance of the transmission and distribution substation components of the delivery system.

Date

## TABLE OF CONTENTS



## INDEX

**ABBREVIATIONS**

# 1.0 Introduction

## 1.1 Background

The reliability of the electric system is an important factor in maintaining a healthy economy, as well as a high degree of customer satisfaction. In recent years, many consumer advocates and regulatory bodies have expressed concern that the reliability of the electric delivery system is being compromised due to an increased focus on competition and profitability. Many states have passed, or are in the process of passing legislation and/or approving regulations intended to refocus attention on maintaining and improving reliability. As time goes on, these laws and/or rules are expected to become more structured and pervasive.

The reliability of the electric system is affected by all three components of the electric system -- generation, transmission and distribution. Generation reliability is ensured by, among other things, maintaining adequate planning and operating reserves. With a few notable exceptions, the establishment and enforcement of specific reserve requirements by regional reliability councils and power pools has resulted in few service interruptions due to the lack of generation capacity[1]. As a result, most service interruptions experienced by end-use customers are the result of interruptions of transmission and distribution (T&D) facilities, not production facilities. Of these delivery system interruptions, the majority of interruptions are generally the result of interruptions of distribution facilities. Even so, interruptions on the transmission system also play an important role in providing reliable electric service and, in some areas, are a key component of overall interruption rates. For one thing, interruptions of transmission facilities, although fewer in number, tend to cover a wider area than distribution interruptions and affect more customers.

One ingredient in maintaining and improving reliability is the development of a consistent set of reliability indices that may be used to measure, report and compare reliability. To date, most industry effort in this regard has addressed the measuring and indexing of total system reliability.

[1] The brown outs experienced during 2001 in California are, of course, notable exceptions.

The Institute of Electrical and Electronic Engineers (IEEE), for example, has developed a draft reliability guideline that seeks to standardize the calculation of reliability indices for end-to-end electric utility systems.[2] Unfortunately, there is not any comparable guideline for measuring the reliability of just the transmission and distribution substation components of the delivery system.

### 1.2 Purpose

The purpose of this Guide is to provide the Rural Utilities Services (RUS) borrowers and others guidance on the development of reliability indices that may be used for benchmarking the performance of the transmission and distribution substation components of the delivery system. To accomplish this, the Guide establishes certain common definitions, measurement techniques and indices in an attempt to ensure consistent and comparable calculations. Without such standards, meaningful benchmarking would be impossible.

By developing reliability benchmark measures for transmission and distribution substations, G&Ts and their distribution members will obtain a planning and management tool to consistently measure and evaluate reliability performance to the delivery point. The development of these benchmark measures is not intended to supplant the draft IEEE standard reliability measures but, rather, to build from and add further definition. Thus, it is hoped that the results will complement and augment the efforts by IEEE and others and to arrive at comparative indices and measurements that will be an important tool in enhancing system reliability. (Refer to the new RUS Bulletin on reliability).

### 1.3 Caveats

It is important to list several caveats at the outset. First, the guidelines contained herein focus on outages of that portion of the transmission system that directly supplies the delivery points serving the distribution cooperative member-systems (or similar points to other wholesale customers). Sometimes this is referred to as the subtransmission system. It does not address

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[2] IEEE P1366 Draft Full Use Guide for Electric Power Distribution Reliability Indices, prepared by the Working Group on System Design, Draft #9, dated December 23, 2002. While the guide refers to "Distribution, Reliability Indices," the indices really focus on total system reliability.

the impact of outages on the bulk power supply facilities. Second, the guidelines do not address the impact of outages of primary distribution delivery facilities (i.e., outages of facilities occurring on the load side of the delivery point). Finally, the reliability indices defined in this guide are intended for benchmarking purposes only, not to set standards of performance.

### 1.4 Reference Documents

The following documents have been referenced in the preparation of this study:

- IEEE P1366 Trial Use Guide for Electric Power Distribution Reliability Indices, prepared by the Working Group on System Design, Draft #9, dated December 23, 2002.
- REA Bulletin 161-1, Interruption Reporting and Service Continuing Standards for Electric Distribution Systems, March 1972.

## 2.0 Definitions

The following definitions were adopted for use in this guide:

1. **Customers Served (at a Delivery Point)** - The number of Customers Served at a Delivery Point is based upon an end-of-year annual customer count, generally one customer per meter. In the case of some installations of dual fuel, storage water heating, cycled air conditioning or other special programs, there may be more than one meter serving the customer. These installations are counted as a single customer. All other meters are counted as one customer (except for non-billed customer submeters).[3] In the case of non-metered accounts (street lights, area lights and other flat rate accounts) some judgment may be necessary to arrive at an accurate customer count. Generally non-metered accounts used for street and highway lighting need to be counted as single customers per account. On the other hand, non-metered area and security lighting associated with a customer premises or business location need not be counted since the use is associated with a primary account.
2. **Delivery Point** - For purposes of this study, a delivery point is defined as the point at

[3] This definition deviates slightly from draft IEEE Standard P1366 in that the draft standard simply counts each meter as a customer, apparently not taking into account that some customers have multiple meters and some flat rate customers may not have meters

which power and energy from the G&T is delivered to the distribution cooperative. Depending on the G&T and the particular Delivery Point, this may be the high side of a Distribution Substation, the low side of a Distribution Substation, a Transmission Substation or a point on a Transmission or Distribution line.

3. **Distribution Substations** - Distribution Substations generally function as Delivery Points that directly serve retail customers at voltages that are typically below 34.5 kV.
4. **Distribution Substation Equipment** - All equipment from the source side bushings of the substation high side breaker or fuse to the load side bushings of the feeder breakers or OCRs.
5. **Foreign Transmission** - Foreign Transmission is defined as transmission facilities that are owned and operated by companies other than the G&T that directly serve distribution member-system Delivery Points. Foreign owners may be IOUs, independent transmission companies, federal transmission owner or another G&T.
6. **Interruption** - The loss of service to one or more customers connected to the Delivery Point resulting from the outage of one or more components on the transmission system or in the Delivery Point substation.
7. **Interruption Duration** - The period (measured in minutes) from the initiation of an interruption to a customer until service has been restored to that customer. For purpose of this study, the duration extends until service is restored to all customers of a delivery point regardless of whether restoration to a portion of the affected customers occurred partway through the interruptions through actions of the G&T or the distribution system operator.
8. **Interruption, Momentary Event**- An interruption of less than five minutes in duration limited to the period required to restore service by an interruption device. As such, switching operations must be completed within a period of less than five minutes. This definition includes all reclosing operations which occur in less than five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds, those momentary interruptions shall be considered one momentary interruption event.
9. **Interruption, Sustained** - Any interruption five minutes or longer in duration.
10. **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 of service to customers, depending on system configuration.

11. **Reporting Period** - The Reporting Period is assumed to be a calendar year January through December, unless otherwise stated.
12. **Transmission Exposure Miles** - Total miles of transmission or subtransmission lines that directly serve Delivery Points. The distance is measured as the total miles of lines of transmission from the nearest breaker(s) that protects the Delivery Point. The measurement for three terminal lines includes the total exposure miles serving the Delivery Point. Exposure Miles are reported for the normally closed configuration that serves the Delivery Point.

## 3.0 Reliability Indices

The following reliability indices are recommended for benchmarking the reliability of the transmission and distribution substation components of the delivery system.

Basic factors

These basic factors specify the data needed to calculate the indices.

i denotes an interruption event

| | | |
|---|---|---|
| $r_i$ | = | Restoration Time for each Interruption Event |
| TE | = | Transmission Exposure Miles |
| E | = | Event |
| D | = | Delivery Point |
| T | = | Total |
| $IM_E$ | = | Number of Momentary Interruption Events |
| $N_D$ | = | Number of Interrupted Delivery points for each Interruption Event |
| $N_i$ | = | Number of Interrupted Customers for each Interruption event During Reporting Period |
| $N_{TD}$ | = | Total Number of Delivery Points Served for the Area Being Indexed |
| $N_T$ | = | Total Number of Customers Served for the Area Being Indexed |

$N_{TE}$ = Total Number of Exposure Miles for the Area Being Indexed

**3.1 Traditional Reliability Indices (Sustained Interruptions)**

The following four indices are generally consistent with the indices defined in draft IEEE P1366, modified, of course, to apply to interruptions on the specified transmission systems and distribution substations:

1. **SAIFI:** System Average Interruption Frequency Index (sustained interruptions). This index, which approximately 81 percent of the utilities responding to a 1997 IEEE survey use, is designed to provide a measure of how often a customer experiences a sustained outage in a defined area.

   $$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

   To calculate the index, use the following equation:

   $$\text{SAIFI} = \frac{\Sigma N_i}{N_T}$$

2. **SAIDI:** System Average Interruption Duration Index. This index, used by approximately 83 percent of the respondents to the 1997 IEEE survey, measures the average minutes (or hours) of interruption per customer.

   $$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customers Served}}$$

   To calculate the index, use the following equation:

   $$\text{SAIDI} = \frac{\Sigma r_i N_i}{N_T}$$

3. **CAIDI:** Customer Average Interruption Duration Index. This index represents the average time required to restore service to the customer per sustained interruption. Approximately 75 percent of the respondents to the 1997 IEEE survey use this index.

$$\text{CAIDI} = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$$

To calculate the index, use the following equation:

$$\text{CAIDI} = \frac{\Sigma r_i N_i}{\Sigma N_i} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

4. **ASAI:** Average Service Availability Index. This index, used by approximately 53 percent of the respondents to the 1997 IEEE survey, represents the fraction of time, often expressed in percentage, that a customer has power provided during the reporting period.

$$\text{ASAI} = \frac{\text{Customer Minutes Service Availability}}{\text{Customer Minutes Service Demand}}$$

To calculate the index, use the following equation:

$$\text{ASAI} = \frac{N_T \times (\text{Number of hours/yr}) - \Sigma r_i N_i}{N_T \times (\text{Number of hours/yr})}$$

Note: There are 8760 hours in a non-leap year, 8784 hours in a leap year

**3.2 G&T Specific Reliability Indices (Sustained Interruptions)**

In addition to the four traditional indices, four indices specifically focused on G&T systems are recommended:

1. **SADPIFI:** System Average Delivery Point Interruption Frequency Index. This index, which measures the average number of interruptions per delivery point for the system, is similar to SAIFI but is based upon delivery points rather than customers.

$$\text{SADPIFI} = \frac{\text{Total Number of Delivery Point Interruptions}}{\text{Total Number of Delivery Points Served}}$$

To calculate the index, use the following equation:

$$SADPIFI = \frac{\Sigma N_D}{N_{TD}}$$

2. **SADPIDI:** System Average Delivery Point Interruption Duration Index. This index measures the average interruption duration per delivery point. It is similar to SAIDI, but based upon delivery points rather than customers.

$$SADPIDI = \frac{\text{Sum of Delivery Point Interruption Durations}}{\text{Total Number of Delivery Points Served}}$$

To calculate the index, use the following equation:

$$SADPIDI = \frac{\Sigma r_i N_D}{N_{TD}}$$

3. **SAILMI:** System Average Interruption Line Miles Index. This index measures the number of transmission caused interruptions per transmission exposure mile.

$$SAILMI = \frac{\text{Total Number of Delivery Point Interruptions}}{\text{Transmission Exposure Miles}}$$

To calculate the index, use the following equation:

$$SAILMI = \frac{\Sigma N_D}{N_{TE}}$$

4. **SADLMI:** System Average Duration Line Miles Index. This index is somewhat similar to SAILMI, measuring system average duration of transmission caused interruptions per transmission exposure mile.

$$SADLMI = \frac{\text{Sum of Delivery Point Interruption Durations}}{\text{Transmission Exposure Miles}}$$

To calculate the index, use the following equation:

$$SADLIMI = \frac{\Sigma r_i N_D}{N_{TE}}$$

### 3.3 Momentary Indices

Momentary interruptions have a significant impact on a customer's reliability experience. In fact, many utilities report anecdotally that customers often seem more concerned about momentary interruptions than sustained interruptions. Measuring momentary reliability, however, requires an enhanced focus and more extensive data gathering for the development of meaningful transmission reliability indices. Momentary Indices may either be calculated for each momentary outage, or by Momentary Event. For the purposes of this guide, all Momentary Indices are assumed to be calculated by Momentary Event. The following momentary indices are recommended for use in benchmarking the performance of the transmission and distribution substation components of the delivery system.

1. **MAIFI:** Momentary Average Interruption Frequency Index. This index, used by approximately 18 percent of the respondents to the 1997 IEEE survey, is similar to SAIFI but tracks the average frequency of momentary interruptions.

$$\text{MAIFI} = \frac{\text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

To calculate the index, use the following equation:

$$\text{MAIFI}_E = \frac{\sum IM_E N_i}{N_T}$$

2. **MSADPIFI:** Momentary System Average Delivery Point Interruption Frequency Index. This index, which measures the average number of momentary interruptions per delivery point for the system, is similar to MAIFI but is based upon delivery points rather than customers.

$$\text{MSADPIFI} = \frac{\text{Total Number of Momentary Delivery Point Interruptions}}{\text{Total Number of Delivery Points Served}}$$

To calculate the index, use the following equation:

$$\text{MSADPIFI} = \frac{\sum IM_E N_D}{N_{TD}}$$

3. **MSAILMI:** Momentary System Average Interruption Line Miles Index. This index measures the overall transmission system interruptions per load serving exposure mile.

$$\text{MSAILMI} = \frac{\text{Total Number of Momentary Delivery Point Interruptions}}{\text{Transmission Exposure Miles}}$$

To calculate the index, use the following equation:

$$\text{MSAILMI} = \frac{\sum IM_E N_D}{N_{TE}}$$

These indices are currently in use by several G&Ts across the country to benchmark reliability performance within their organizations and with other G&Ts. Multiple years of consistently tracking this data can lead to comprehensive reporting to management, distribution cooperative members, RUS, regulatory bodies and transmission organizations.