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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

BULLETIN 1730A-119
RD-GD-2009-58

SUBJECT: Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems

TO: All Distribution Borrowers

EFFECTIVE DATE: Date of approval.

OFFICE OF PRIMARY INTEREST: Electric Staff Division, Distribution Branch.

INSTRUCTIONS: This bulletin replaces REA Bulletin 161-1, dated March 31, 1972.

AVAILABILITY: This bulletin can be accessed via the internet at:

http://www.usda.gov/rus/electric/bulletins.htm.

PURPOSE: To provide guidance on recording and reporting service interruptions and outages, the calculation of industry standard indices for measuring distribution system performance and promotion of consistent outage recordkeeping and reporting among borrowers.

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03/24/09
Date

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ABBREVIATIONS

AMR – Automated Meter Reading
CSR – Customer Service Representative
IEEE – The Institute of Electrical and Electronics Engineers
IVR – Interactive Voice Response
MAIFI – Momentary Average Interruption Frequency Index
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SCADA – Supervisory Control and Data Acquisition
T_{MED} – Major event day identification threshold value

DEFINITIONS

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

> Power supply interruption – Any interruption originating from the transmission system, sub-transmission system, or the substation, regardless of ownership.
>
> Planned interruption – Any interruption scheduled by the distribution system to safely perform routine maintenance.
>
> All other interruptions – All interruptions excluding power supply, major event, and those that are planned.

Major event – An interruption or group of interruptions caused by conditions that exceed the design and operational limits of a system. See IEEE Standard 1366-2003 and Exhibit E of this document.

Major event day – As defined by IEEE Standard 1366, a day in which the daily SAIDI exceeds a threshold value, T_{MED}. For the purpose 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 when the energy delivery system experiences stresses beyond those normally expected—such as severe weather. Activities that occur on major event days should be analyzed and reported separately.

Outage – The state of a component when it is not available to perform its intended function as a result of an event directly associated with that component. An outage could cause an interruption of service to customers, depending on system configuration. This definition does not apply to generation outages.

FORMS

RUS Form 7, “Financial and Statistical Report”
RUS Form 300, “Rating Review Summary”

1 PURPOSE AND SCOPE

This bulletin provides guidance on recording and reporting service interruptions and outages and the calculation of industry standard indices for measuring distribution system performance. One of the goals of the bulletin is to promote consistent outage recordkeeping and reporting among borrowers, and to assist them in implementing the major event day methodology that has been adopted by IEEE. Consistency in outage recordkeeping among borrowers will provide opportunities for performance benchmarking. In addition, to help electric systems collect useful and consistent data on outages, this bulletin harmonizes outage cause codes used by the Rural Utilities Service (RUS) and IEEE.

2 INTERRUPTION REPORTING

a The Trouble Ticket. The generation of a trouble ticket is the first step in interruption reporting.

(1) 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.

(2) A trouble ticket is traditionally the result of a telephone call from a member reporting a service problem or interruption. Such telephone calls usually are taken by customer service representatives (CSR) using manual “trouble ticket” forms. However, with newer technology, borrowers can automate this process and render the traditional trouble ticket paperless.

(3) Borrower personnel should consider the process of interruption data gathering, reporting, and analysis and determine the point at which these data should be put in an electronic format. Because of the flexibility of software systems and the advent of services and products such as call centers and interactive voice response systems, the borrower has many choices to improve its performance in this area.

b Manual Trouble Ticket. The simplest interruption reporting is the use of a form as shown in Exhibit A. An employee could fill out this type of form manually while talking 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 could be used to generate any interruption analysis or reports the borrower may find useful.

c 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 Exhibit C.

d The Interruption Report. The interruption report is used to document a service interruption.

(1) 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.

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

(3) See Exhibit B for a sample Interruption Report.

e Reports to RUS. RUS Borrowers that borrow funds from RUS are required to report the system average annual interruption minutes per consumer on Form 7 and Form 300. Shown in Table 1 is Part G of Form 7. Form 7 calls for four separate SAIDIs, as well as the total interruption time. The definitions of the terms used in Part G can be found in Part 2, Definitions.

Table 1. RUS Form 7, Part G

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					

f Changes to Forms 7 and 300. Previously, Forms 7 and 300 called for Average Hours Per Consumer Per Year for (1) Power Supplier, (2) Extreme Storm, (3) Pre-arranged, and (4) All Other. Note that the SAIDI in minutes is now required, instead of average hours per consumer and that “major event” is a category in place of “major storm.” If SAIDI data is not available for previous years, use average hours per consumer per year, multiplied by 60 to convert the data to minutes. It should be noted, however, that other entities, such as various state commissions, require SAIDI to be reported in minutes.

3 INTERRUPTION ANALYSIS

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

a Cause Codes and Equipment Codes. Two codes have traditionally been associated with interruption reporting: cause codes and equipment codes. Cause codes indicate the initiating condition which would include decay, animals, lightning, tree limbs, etc. while the equipment code indicates what equipment was involved, such as a broken insulator. However, when a protective device such as a fuse operates (as designed) to disconnect a faulted conductor, no equipment has failed or been damaged. Therefore, a "special" equipment code is also needed to indicate that no failure of equipment or material defect occurred. Every interruption has a cause, but not every interruption results in damaged or failed equipment. Therefore, in the case where no equipment was damaged, the corresponding code in Table 3, "999, No Equipment Failure", would be used. Including this special code ensures that 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 Table 2, and equipment codes are shown in Table 3.

b Weather Condition and Voltage Level Codes. In addition to cause codes and equipment codes, incorporating weather condition and voltage level codes may be beneficial.

(1) Weather Condition Codes. Weather condition codes indicate the conditions that existed when the interruption occurred; they are not to be confused with the cause codes, which indicate a weather component that might have initiated an interruption. These are shown in Table 4.

(2) Voltage Level Codes. 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. Table 5 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. The borrower's engineer may be able to determine other improvements based on these data as well.

(3) Explanation of Codes. All of the codes are formatted so that summary and high level reports are easy to produce based on the data in the interruption report. The borrower may choose to use additional codes for more detailed information and analysis. The cause codes listed in

Table 2 represent an important development. Cause codes have been adapted to align with both RUS and IEEE approaches. Note that the codes recommended in Column 1 of Table 2 link RUS's codes that borrowers are accustomed to seeing with the codes prescribed by IEEE. Borrowers are encouraged to use the numbering system outlined in the first column to categorize outages. The numbering system is flexible so that borrowers can add their own cause codes within each subcategory. Subcategory coding can be used to isolate problems with specific types or brands of equipment on the system and to monitor their performance.

Table 2. Cause Codes

Cause 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 planned
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 installation/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	Borrower 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[2]			
999	D	9	Cause unknown

[1] This cause code is used for outages caused by something on equipment not owned by the distribution borrower. If an interruption is caused by something on the distribution borrower's own transmission system, a specific cause should be used.
[2] Interruptions marked as "Cause unknown" should be further investigated to try to determine probable cause.

Table 3. Equipment/Material Failure Codes	
Failure 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 dead end
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	Transformer 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

Table 4. Weather Condition 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

Table 5. Voltage Level Codes

001	< 1 KV(Secondary/Low Voltage)
002	5 KV
003	15 KV
004	25 KV
005	35 KV
006	60 KV
007	> 60 KV

4 POWER QUALITY METRICS

a Use and Analysis of Interruption Data. The time spent collecting the data described above will be wasted unless the data are analyzed and the results are used as a tool to improve the distribution system performance.

(1) The data can be useful in many ways. For example, interruption records, which included data on equipment failures, led a certain utility to discover that two lightning arrester manufacturers had bad batches of arresters, which were failing prematurely. Another utility used information on lightning damage and location to determine lightning-prone areas in its territory. The utility then selectively improved the grounding in those areas, resulting in a least-cost reduction in interruptions caused by lightning and a reduction in equipment damage.

(2) The ultimate goal of these efforts is to reduce the number and duration of interruptions, improving reliability. Analysis of interruption trends, derived from consistent data collection over many years, helps ensure that money invested to improve reliability is spent wisely.

b Definition and Use of the Major Indices. The definition of the most significant interruption-related indices and calculations will be discussed in this section. 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

(1) IEEE Standard 1366-2003[1] 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.

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

(2) As noted 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 calculating duration is determined by when the borrower knows about an 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 still should be counted as an interruption. However, in these cases, the duration should be logged as the estimated amount of time required to repair the problem, including travel time.

(3) 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 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 Form 7.)

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

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

(5) 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 the distribution system has limited resources to respond to an interruption that covers an extensive portion of its territory.

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

c Determination of a Major Event. Certain things are beyond the control of the distribution system—primarily natural disasters. Form 7 requires the SAIDI for these interruptions to be reported separately in Part G, Column (b), "Major Event**.**" It should not be included in Part G, Column (d), "All Other."

(1) Previously, there has been no hard and fast rule of what constitutes a major event. It has usually been defined as an event that lasts a specified period of time and causes an interruption for at least a specified number of customers.

(2) For example, an ice storm that results in interruptions of up to 10 days and causes an interruption for 80% of customers is clearly a major event. In this case, the interruption records would be kept separately. In calculating the SAIDI for the year, the interruptions from this event should be included in Column (b).

(3) What about a severe thunderstorm that caused some customers interruptions of up to 25 hours and where 5% of the customers 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.

(4) It is desirable to be more consistent across the nation and to take into account the fact that distribution systems with lower SAIDIs 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." The Group has defined a "major event" as an interruption or series of interruptions that exceed reasonable design and/or operational limits of the electric power system. With the issuance of this Bulletin, RUS encourages all borrowers to start using this approach. All outages that occur during a day found to be a "major event day" should be reported in Form 7, Part G, Column (b).

(5) This methodology is fully described in IEEE 1366, "Guide for Electric Power Distribution Reliability Indices," and in Exhibit E of this Bulletin. The calculation involves taking the daily SAIDI values for the last five years and the natural logarithm of each value in the data set. For those who have automated systems for recording reliability information, this calculation should be easily obtainable. For those who use manual systems, (RUS offers a simple spreadsheet, prepared by the NRECA T&D Engineering Committee, to determine the threshold level for major event

days. This spreadsheet can be downloaded from RUS's website at https://www.rd.usda.gov/files/UEP_1730A-119_Outage_Data_Sheet.xls.

(*NOTE: Spreadsheet must be "saved" to your hard drive first and then opened. If spreadsheet is "opened" directly from link, it will NOT work correctly.*)

(6) The Interruption Report (Exhibit B) is used to calculate the values required on 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 is in Exhibit D.

5 SERVICE CONTINUITY OBJECTIVES

a Demand for Good Service. Rural electric systems now provide power to everything from the single-family farm to the computer network server farm

(1) As utility service entities, borrowers 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 borrower 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 of "four nines" (99.99%).

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

(3) RUS's 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 borrower should look at each category when determining or modifying operating and design practices and criteria. The power supplier should be consulted if power supply interruptions are excessive. For Form 300, Part II, 7(a), the "All Other" classification will be the primary category for evaluation. Table 6 shows the current guideline:

Table 6. 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 borrower sets a reliability goal, personnel can take a proactive role in bringing it about through system planning and budgeting.

(1) A thorough analysis of interruption causes, number of accounts affected, and durations can tell the engineering and operations staff where to concentrate their efforts. Table 7 shows several areas to consider for review.

Table 7. 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

(2) Prioritizing the likely contributors of interruptions will enable the engineer to better target capital expenditures to improve performance of the system. Continuous improvement in reliability provides several long-term benefits including increased customer satisfaction, lower maintenance expenses, lower demands on operations personnel, better system performance during extreme weather events, and improved safety for line workers and the general public. Specific actions needed to achieve or maintain a satisfactory interruption level should be addressed in the construction work plan.

c Other Indices. There are several other indices that the borrower might want to use. Three of these—SAIFI, SAIDI, and CAIDI—were discussed above. Another that might be considered is MAIFI—Momentary Average Interruption Frequency Index—a measure of the number of breaker operations that do not go to lockout. MAIFI could be used to measure system coordination. It also might be used as one measure of the quality of the power supply by recording momentary transmission interruptions.

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	

INTERRUPTION REPORT

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<tr><td>CAUSE</td><td>EQUIP</td><td>WEATHER</td><td>RUS FORM 7</td></tr>
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<tr><td colspan="12">REVIEWED BY

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

CALL CENTERS AND IVR

1 CALL CENTERS

a Call centers have grown out of a need by borrowers to handle larger call volumes with people rather than machines. The call center can be staffed either in-house by borrower employees or outsourced to a call center at a different location. Because of economics or the desire to have high-volume call handling capabilities with live customer service representatives (CSR), outsourcing may be the way to go for many borrowers. In either case, the CSR will talk to the member, gathering information needed to identify the member and the location of the interruption, along with any other information the member may have about the interruption. The CSR also may be able to share information about the interruption with the member if the borrower is already aware of it. Call centers could then electronically forward such 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.

b Successful operation of a call center involves being sure the CSRs are trained to provide a positive image of the borrower. The member should not be able to tell whether the CSR is a borrower 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—such as service turned off for nonpayment. This database should be updated at least daily. These CSRs also should have access to information concerning status of interruptions so they can keep members informed as the interruption progresses.

2 INTERACTIVE VOICE RESPOSE (IVR) SYSTEMS

a If a borrower is willing to use advanced call answering technologies it may want to investigate the use of an interactive voice response (IVR) system, which uses electronic voice messaging to handle large call volumes fast and efficiently. These systems are especially attractive if the borrower is using an automated interruption management system. As in the call center application, these systems can be implemented either in-house or outsourced to third-party vendors. Often, this decision is based on a borrower’s ability to size its incoming phone lines to handle the phone traffic needed when large interruptions occur. For example, the existing borrower capability may be only 12 to 24 incoming lines, while third-party facilities may be capable of more than 500 incoming lines. Such increased call handling capability is especially critical if the borrower is using an automated outage management system. The borrower also may consider using an emergency overload system, where the calls go to the third party only after a set call volume is reached.

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

c IVR systems also require access to a current customer database giving account location and status. Most IVR systems use customer phone numbers for account recognition. This can be done using caller ID systems or by having customers enter their phone numbers in response to requests from the IVR. Using phone numbers for account recognition requires borrowers to be diligent in keeping the numbers current for all accounts. For multiple accounts, the IVR system must have a way to determine which account is actually out. This can be done if the IVR uses text messaging of some account location field, which would uniquely identify the location with the member; or the IVR, using speech recognition, could ask the customer to leave a message describing the proper location. If both of these methods fail, the IVR could simply forward the customer's call to a person for resolution.

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

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 timeline format.

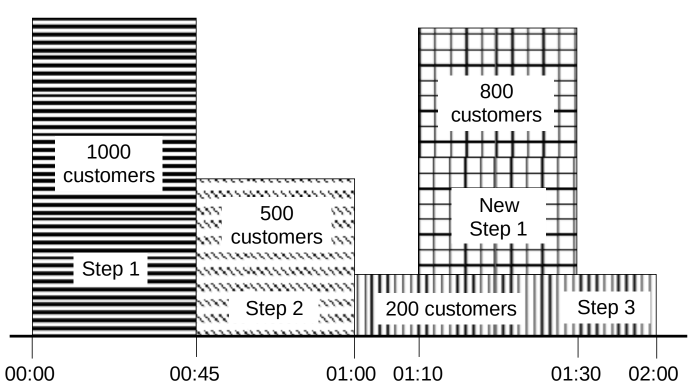
Relative Time	Description	Customers	Duration (minutes)	Customer-Minutes of Interruption
00:00	1,000 customers interrupted.			
00:45	500 customers restored; 500 customers still out of service.	500	45	22,500
1:00	Additional 300 customers restored; 200 customers still out of service.	300	60	18,000
1:10	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:

Step Restoration Time Chart

(Designer: X axis is Time; Y axis is Number of Customers



CALCULATION OF MAJOR EVENT DAYS

1 INTRODUCTION

The following process ("Beta Method") is used to identify major event days. This is a methodology developed by IEEE, available in IEEE Standard 1366™-2003, "IEEE Guide for Electric Power Distribution Reliability Indices." 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 supersedes previous major event definitions.

2 MAJOR EVENT DAYS

a. Definition. A major event day is a day when 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 major event days, all indices should be calculated based on removal of the identified days.

b. Calculation of Threshold. 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, 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 this equation:

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

(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.

NORMALIZATION FOR WEATHER

Accurate and useful reliability reporting eventually will require ways to accommodate and understand the effect of lightning. The weather varies across the country and it 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. Normalizing the interruption data for the incidence of lightning may be a useful area to explore. Plotting the number of customer interruptions and cloud-to-ground lightning strikes may point to areas where actions are needed to maintain or improve a system's lightning protection.

RELIABILITY INDICES FOR SUBSTATION COMPONENTS

1 INTRODUCTION

a 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.

(1) 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.

(2) 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.[2] 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. Interruptions of transmission facilities, although fewer in number, tend to cover a wider area than distribution interruptions and affect more customers.

(3) 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

(4) 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.[3] Unfortunately, there is not any comparable guideline for measuring the

[2] The brown outs experienced during 2001 in California are, of course, notable exceptions.
[3] 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.

reliability of just the transmission and distribution substation components of the delivery system.

b Purpose

(1) This Exhibit provides 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 Exhibit 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.

(2) 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.

c 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 borrower member-systems (or similar points to other wholesale customers). Sometimes this is referred to as the subtransmission system. It does not address 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.

d Reference Document

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 has been used as a reference for preparing this exhibit.

2 DEFINITIONS

The following definitions were adopted for use in this exhibit:

a 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).[4] 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.

b Delivery Point

For purposes of this study, a delivery point is defined as the point at which power and energy from the G&T is delivered to the distribution borrower. 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.

c Distribution Substations

Distribution Substations generally function as Delivery Points that directly serve retail customers at voltages that are typically below 34.5 kV.

d 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.

e 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.

[4] 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

f **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.

g **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.

h **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.

i **Interruption, Sustained**

Any interruption five minutes or longer in duration.

j **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.

k **Reporting Period**

The Reporting Period is assumed to be a calendar year January through December, unless otherwise stated.

l **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 RELIABILITY INDICES

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

(1) 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

(2) 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:

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

(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:

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

(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:

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

(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:

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

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

(3) 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:

$$\text{SADPIFI} = \frac{\sum N_D}{N_{TD}}$$

(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.

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

To calculate the index, use the following equation:

$$\text{SADPIDI} = \frac{\sum r_i N_D}{N_{TD}}$$

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

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

To calculate the index, use the following equation:

$$\text{SAILMI} = \frac{\sum N_D}{N_{TE}}$$

(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.

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

To calculate the index, use the following equation:

$$\text{SADLIMI} = \frac{\sum r_i N_D}{N_{TE}}$$

(4) 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:

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

(5) Use

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 borrower members, RUS, regulatory bodies, and transmission organizations.