IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power & Energy Society

Sponsored by the
Transmission and Distribution Committee

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Abstract: Distribution reliability indices and factors that affect their calculations are defined in this guide. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.
Keywords: circuits, distribution reliability indices, distribution systems, electric power, IEEE 1366, reliability indices

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Introduction

This introduction is not part of IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

This guide was originally developed in 1998 to create indices specifically designed for distribution systems. Other groups have created indices for transmission and industrial systems, but none were available for distribution. This group will continue working in this area by refining the information contained in this guide.

This guide was updated in the 2003 revision to clarify existing definitions and to introduce a statistically based definition for classification of Major Event Days. The working group created a methodology, 2.5 Beta Method, for determination of Major Event Days. Once days are classified as normal or Major Event Days, appropriate analysis and reporting can be conducted.

This 2012 revision of the guide clarified several of the definitions and introduced two new indices. The new indices are CELID-s and CELID-t, customers experiencing long interruption durations (both single and total). A section was also added to explain the investigation of catastrophic days.

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1. Overview

1.1 Introduction

This full-use guide has been updated to clarify existing definitions, introduce two additional reliability indices, and add a discussion of Major Event Days and catastrophic days (see 5.3).

1.2 Scope

This guide identifies distribution reliability indices and factors that affect their calculation. It includes indices, which are useful today, as well as ones that may be useful in the future. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.

1.3 Purpose

The purpose of this guide is twofold. First, it is to present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it is to provide guidance for new personnel in the reliability area and to provide tools for internal as well as external comparisons. In the past, other groups have defined reliability indices for transmission, generation, and distribution but some of the definitions already in use are not specific enough to be wholly adopted for distribution. Users of this guide should recognize that not all utilities would have the data available to calculate all the indices.

2. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary: Glossary of Terms and Definitions*[1] should be consulted for terms not defined in this clause.

connected load: Connected transformer or metered demand (to be clearly specified when reporting) on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak.

customer: A metered electrical service point for which an active bill account is established at a specific location.

customer count: The number of customers either served or interrupted, depending on usage.

distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission system to the customer.

NOTE—The distribution system is generally considered to be anything from the distribution substation fence to the customer meter. Often the initial overcurrent protection and voltage regulators are within the substation fence and are considered part of the distribution system.[2]

forced outage: The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component.

interrupting device: A device to stop the flow of power, usually in response to a fault. Operation of the device can be accomplished by manual, automatic, or remotely operated methods. Examples include circuit breakers, line reclosers, line fuses, disconnect switches, sectionalizers, and/or others.

interruption: The total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics. *See also:* **outage.**

interruption duration: The time period from the initiation of an interruption until service has been restored to the affected customers.

NOTE—The process of restoration may require restoring service to small sections of the system until service has been restored to all customers. See 4.3.2 for a step-restoration example. Each of these individual steps should be tracked, collecting the start time, end time, and number of customers interrupted for each step.

interruptions caused by events outside of the distribution system: Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and may last for a long time.

lockout: When a reclosing interrupting device is in the open position and no further operations of that device are allowed without manual intervention.

[1] *IEEE Standards Dictionary: Glossary of Terms and Definitions* is available at http://shop.ieee.org.
[2] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

Major Event: Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day. *See also:* **Major Event Day.**

Major Event Day (MED): A day in which the daily system System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value. 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 during severe weather). Activities that occur on Major Event Days should be separately analyzed and reported.

NOTE—See Major Event Day classification in 3.5.

momentary interruption: The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device.

NOTE—Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.

momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device.

NOTE 1—Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption.

NOTE 2—If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

outage: The loss of ability of a component to deliver power.

NOTE 1—An outage may or may not cause an interruption of service to customers, depending on system configuration.

NOTE 2—This definition derives from transmission and distribution applications and does not apply to generation outages.

planned interruption: The loss of electric power to one or more customers that results from a planned outage.

NOTE 1—This derives from transmission and distribution applications and does not apply to generation interruptions.

NOTE 2—The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows: If it is possible to defer the interruption, then the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.

planned outage: The intentional disabling of a component's capability to deliver power, done at a preselected time, usually for the purposes of construction, preventative maintenance, or repair.

reporting period: The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year, unless otherwise stated.

step restoration: The process of restoring all interrupted customers in stages over time.

sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.

total number of customers served: The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

unplanned interruption: The loss of electric power to one or more customers that does not result from a planned outage.

3. Definitions of reliability indices

3.1 Basic factors

The basic factors defined below specify the data needed to calculate the reliability indices.

NOTE—The subscript 'i' denotes an interruption event.

CI Customers interrupted

CMI Customer minutes of interruption

CN Total number of distinct customers who have experienced a sustained interruption during the reporting period

$CN_{(k\geq n)}$ Total number of customers who have experienced *n* or more sustained interruptions during the reporting period

$CN_{(k\geq S)}$ Total number of customers that experienced S or more hours duration

$CN_{(k\geq T)}$ Total number of customers that experienced T or more hours duration

$CNT_{(k\geq n)}$ Total number of customers who have experienced *n* or more sustained interruptions and momentary interruption events during the reporting period

E Event

IM_i Number of momentary interruptions

IM_E Number of momentary interruption events

k Number of interruptions experienced by an individual customer in the reporting period

L_i Connected kVA load interrupted for each interruption event

L_T Total connected kVA load served

N_i Number of interrupted customers for each sustained interruption event during the reporting period

N_{mi} Number of interrupted customers for each momentary interruption event during the reporting period

$\mathbf{N_T}$	Total number of customers served for the area
$\mathbf{r_i}$	Restoration time for each interruption event
$\mathbf{T_{MED}}$	Major Event Day threshold

3.2 Sustained interruption indices

3.2.1 SAIFI: System Average Interruption Frequency Index

The System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Eq. (1).

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \tag{1}$$

To calculate the index, use Eq. (2).

$$\text{SAIFI} = \frac{\sum N_i}{N_T} = \frac{\text{CI}}{N_T} \tag{2}$$

3.2.2 SAIDI: System Average Interruption Duration Index

The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. Mathematically, this is given in Eq. (3).

$$\text{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}} \tag{3}$$

To calculate the index, use Eq. (4).

$$\text{SAIDI} = \frac{\sum r_i N_i}{N_T} = \frac{\text{CMI}}{N_T} \tag{4}$$

3.2.3 CAIDI: Customer Average Interruption Duration Index

The Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. Mathematically, this is given in Eq. (5).

$$\text{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}} = \frac{\text{CMI}}{\text{CI}} \tag{5}$$

To calculate the index, use Eq. (6).

$$\mathrm{CAIDI} = \frac{\sum r_i N_i}{\sum N_i} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}} \tag{6}$$

3.2.4 CTAIDI: Customer Total Average Interruption Duration Index

The Customer Total Average Interruption Duration Index (CTAIDI) represents the total time in the reporting period that average customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated, except that those customers with multiple interruptions are counted only once. Mathematically, this is given in Eq. (7).

$$\mathrm{CTAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Distinct Customers Interrupted}} \tag{7}$$

To calculate the index, use Eq. (8).

$$\mathrm{CTAIDI} = \frac{\frac{\sum r_i N_i}{\mathrm{CN}}}{} = \frac{CMI}{CN} \tag{8}$$

NOTE—In tallying Total Number of Customers Interrupted, each individual customer should be counted only once regardless of the number of times interrupted during the reporting period. This applies to definitions provided in 3.2.4 and 3.2.5.

3.2.5 CAIFI: Customer Average Interruption Frequency Index

The Customer Average Interruption Frequency Index (CAIFI) gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once, regardless of the number of times interrupted for this calculation. Mathematically, this is given in Eq. (9).

$$\mathrm{CAIFI} = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}} \tag{9}$$

To calculate the index, use Eq. (10).

$$\mathrm{CAIFI} = \frac{\sum N_i}{\mathrm{CN}} = \frac{CI}{CN} \tag{10}$$

3.2.6 ASAI: Average Service Availability Index

The Average Service Availability Index (ASAI) represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given in Eq. (11).

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}} \tag{11}$$

To calculate the index, use Eq. (12).

$$\text{ASAI} = \frac{N_T \times (\text{Number of hours/yr}) - \sum r_i N_i}{N_T \times (\text{Number of hours/yr})} \tag{12}$$

NOTE—There are 8 760 hours in a non-leap year and 8 784 hours in a leap year.

3.2.7 CEMI$_n$: Customers Experiencing Multiple Interruptions

The Customers Experiencing Multiple Interruptions Index (CEMI$_n$) indicates the ratio of individual customers experiencing *n* or more sustained interruptions to the total number of customers served. Mathematically, this is given in Eq. (13).

$$\text{CEMI}_n = \frac{\text{Total Number of Customers that experienced n or more sustained interruptions}}{\text{Total Number of Customers Served}} \tag{13}$$

To calculate the index, use Eq. (14).

$$\text{CEMI}_n = \frac{CN_{(k \geq n)}}{N_T} \tag{14}$$

NOTE—This index is often used in a series of calculations with *n* incremented from a value of 1 to the highest value of interest.

3.2.8 CELID: Customers Experiencing Long Interruption Durations

The Customers Experiencing Long Interruption Durations Index (CELID) indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time. That time is either the duration of a single interruption (s) or the total amount of time (t) that a customer has been interrupted during the reporting period. Mathematically, the Single Interruption Duration equation is given in Eq. (15) and the Total Interruption Duration equation is given in Eq. (17).

Single Interruption Duration:

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced S or more hours duration}}{\text{Total Number of Customers Served}} \tag{15}$$

To calculate the index, use Eq. (16).

$$\text{CELID-s} = \frac{CN_{(k \geq S)}}{N_T} \tag{16}$$

Total Interruption Duration:

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced T or more hours duration}}{\text{Total Number of Customers Served}} \quad (17)$$

To calculate the index, use Eq. (18).

$$\text{CELID-t} = \frac{CN_{(k \geq T)}}{N_T} \quad (18)$$

3.3 Load based indices

3.3.1 ASIFI: Average System Interruption Frequency Index

The calculation of the Average System Interruption Frequency Index (ASIFI) is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers that have relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a system with homogeneous load distribution, ASIFI would be the same as SAIFI. Mathematically, this ASIFI is given in Eq. (19).

$$\text{ASIFI} = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} \quad (19)$$

To calculate the index, use Eq. (20).

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \quad (20)$$

3.3.2 ASIDI: Average System Interruption Duration Index

The calculation of the Average System Interruption Duration Index (ASIDI) is based on load rather than customers affected. Its use, limitations, and philosophy are stated in the ASIFI definition in 3.3.1. Mathematically, ASIDI is given in Eq. (21).

$$\text{ASIDI} = \frac{\sum \text{Connected kVA Duration of Load Interrupted}}{\text{Total Connected kVA Served}} \quad (21)$$

To calculate the index, use Eq. (22).

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \quad (22)$$

3.4 Other indices (momentary)

3.4.1 MAIFI: Momentary Average Interruption Frequency Index

The Momentary Average Interruption Frequency Index (MAIFI) indicates the average frequency of momentary interruptions. Mathematically, this is given in Eq. (23).

$$\mathrm{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}} \tag{23}$$

To calculate the index, use Eq. (24).

$$\mathrm{MAIFI} = \frac{\sum IM_i N_{mi}}{N_T} \tag{24}$$

3.4.2 MAIFI$_E$: Momentary Average Interruption Event Frequency Index

The Momentary Average Interruption Event Frequency Index (MAIFI$_E$) indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption. Mathematically, this is given in Eq. (25).

$$\mathrm{MAIFI_E} = \frac{\sum \text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} \tag{25}$$

To calculate the index, use Eq. (26).

$$\mathrm{MAIFI_E} = \frac{\sum IM_E N_{mi}}{N_T} \tag{26}$$

3.4.3 CEMSMI$_n$: Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events

The Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events Index (CEMSMI$_n$) is the ratio of individual customers experiencing *n* or more of both sustained interruptions and momentary interruption events to the total customers served. Its purpose is to help identify customer issues that cannot be observed by using averages. Mathematically, this is given in Eq. (27).

$$\mathrm{CEMSMI_n} = \frac{\text{Total Number of Customers Experiencing n or More Interruptions}}{\text{Total Number of Customers Served}} \tag{27}$$

To calculate the index, use Eq. (28).

$$\mathrm{CEMSMI_n} = \frac{CNT_{(k \geq n)}}{N_T} \tag{28}$$

3.5 Major Event Day classification

The following process—Beta Method—is used to identify Major Event Days (MED), provided that the natural log transformation of the data results closely resembles a Gaussian (normal) distribution. 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. For more technical detail on derivation of the methodology, refer to Annex B.

A MED 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 MEDs, 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 MED identification T_{MED} value is calculated at the end of each reporting period (typically one year) for use during the next reporting period, as follows:

a) 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 data are available, use all available historical data until five years of historical data are available.

b) Only those days that have a SAIDI/Day value will be used to calculate T_{MED} (do not include days that did not have any interruptions).

c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.

f) Compute the MED threshold, T_{MED}, using Eq. (29).

$$T_{MED} = e^{(\alpha + 2.5\beta)} \tag{29}$$

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

Activities that occur on days classified as MEDs should be separately analyzed and reported.

3.5.1 An example of using the MED definition to identify major events and subsequently calculate adjusted indices that reflect normal operating performance

The following example illustrates the calculation of the daily SAIDI, calculation of the MED threshold T_{MED}, identification of MEDs, and calculation of adjusted indices.

Table 1 gives selected data for all interruptions occurring on a certain day for a utility that serves 2 000 customers.

Table 1—Interruption data for March 18, 1994

Date	Time	Duration (min)	Number of customers	Interruption Type
Mar 18, 1994	18:34:30	20.0	200	Sustained
Mar 18, 1994	18:38:30	1.0	400	Momentary
Mar 18, 1994	18:42:00	513.5	700	Sustained

Note that although the third interruption (at 18:42:00) was not restored until the following day, its total duration counts in the day that the interruption began. Note also that SAIDI considers only sustained interruptions.

For March 18, 1994, daily SAIDI (assuming a 2 000 customer utility) is given in Eq. (30).

$$\mathrm{SAIDI} = \frac{(20 \times 200) + (513.5 \times 700)}{2000} = 181.73\,\mathrm{min} \tag{30}$$

One month of historical daily SAIDI data is used in the following example to calculate the MED threshold T_{MED}. Five years of historical data is preferable for this method, but printing that many values in this guide is impractical, so only one month is used to illustrate the concept. The example data is shown in Table 2.

Table 2—One month of daily SAIDI and ln(SAIDI/day) data

Date	SAIDI/day (min)	ln(SAIDI/day)	Date	SAIDI/day (min)	ln(SAIDI/day)
Dec 1, 1993	26.974	3.295	Dec 17, 1993	0.329	-1.112
Dec 2, 1993	0.956	-0.046	Dec 18, 1993	0	This day is not included in the calculations since no customers were interrupted.
Dec 3, 1993	0.131	-2.033	Dec 19, 1993	0.281	-1.268
Dec 4, 1993	1.292	0.256	Dec 20, 1993	1.810	0.593
Dec 5, 1993	4.250	1.447	Dec 21, 1993	0.250	-1.388
Dec 6, 1993	0.119	-2.127	Dec 22, 1993	0.021	-3.876
Dec 7, 1993	0.130	-2.042	Dec 23, 1993	1.233	0.209
Dec 8, 1993	12.883	2.556	Dec 24, 1993	0.996	-0.004
Dec 9, 1993	0.226	-1.487	Dec 25, 1993	0.162	-1.818
Dec 10, 1993	13.864	2.629	Dec 26, 1993	0.288	-1.244
Dec 11, 1993	0.015	-4.232	Dec 27, 1993	0.535	-0.626
Dec 12, 1993	1.788	0.581	Dec 28, 1993	0.291	-1.234
Dec 13, 1993	0.410	-0.891	Dec 29, 1993	0.600	-0.511
Dec 14, 1993	0.007	-4.967	Dec 30, 1993	1.750	0.560
Dec 15, 1993	1.124	0.117	Dec 31, 1993	3.622	1.287
Dec 16, 1993	1.951	0.668			
NOTE—The SAIDI/day for December 18, 1993 is zero, and the natural logarithm of zero is undefined. Therefore, December 18, 1993 is not considered during the analysis.					

The value of α, the log-average, is the average of the natural logs, and equals -0.555 in this case.

The value of β, the log-standard deviation, is the standard deviation of the natural logs, and equals 1.90 in this example.

The value of $\alpha + 2.5\beta$ is 4.20.

The threshold value T_{MED} is calculated by $e^{(4.20)}$ and equals 66.69 SAIDI minutes per day. This value is used to evaluate the future time period (e.g., the next year).

Table 3 shows example SAIDI/day values for the first month of 1994.

Table 3—Daily SAIDI data, January 1994

Date	SAIDI/Day	Date	SAIDI/Day
Jan 1, 1994	0.240	Jan 17 1994	5.700
Jan 2, 1994	0.014	Jan 18, 1994	0.109
Jan 3, 1994	0.075	Jan 19, 1994	0.259
Jan 4, 1994	2.649	Jan 20, 1994	1.142
Jan 5, 1994	0.666	Jan 21, 1994	0.262
Jan 6, 1994	0.189	Jan 22, 1994	0.044
Jan 7, 1994	0.009	Jan 23, 1994	0.243
Jan 8, 1994	1.117	Jan 24, 1994	5.932
Jan 9, 1994	0.111	Jan 25, 1994	2.698
Jan 10, 1994	8.683	Jan 26, 1994	5.894
Jan 11, 1994	0.277	Jan 27, 1994	0.408
Jan 12, 1994	0.057	Jan 28, 1994	237.493
Jan 13, 1994	0.974	Jan 29, 1994	2.730
Jan 14, 1994	0.150	Jan 30, 1994	8.110
Jan 15, 1994	0.633	Jan 31, 1994	0.046
Jan 16, 1994	0.434		

The SAIDI/day on January 28, 1994 (237.49) exceeds the example threshold value (T_{MED} = 66.69), indicating that the distribution system experienced stresses beyond that normally expected on that day. Therefore, January 28, 1994 is classified as a MED. The SAIDI/day for all other days was less than T_{MED}, indicating that normal stresses were experienced on those days.

To complete the example, indices should be calculated for two conditions:

1) All events included
2) MEDs removed

In most cases, utilities will calculate all of the indices they normally use (e.g., SAIFI, SAIDI, and/or CAIDI). For this example, only SAIDI will be shown. The SAIDI for 1994 for condition 1) above (all events included) is given in Eq. 31.

$$\text{SAIDI} = \sum \text{Daily SAIDI} = 287.35 \tag{31}$$

The SAIDI for 1994 for condition 2) above (MEDs removed), for separate reporting and analysis, is given in Eq. 32.

$$\text{SAIDI} = \sum \text{Daily SAIDI with the MEDs removed} = 49.86 \tag{32}$$

4. Application of the indices

Most utilities store interruption data in large computer databases. Some databases are better organized than others for querying and analyzing reliability data. The following subclause will show one sample partial database and the methodology for calculating indices based on the information provided.

4.1 Sample system

Table 4 shows an excerpt from one utility's customer information system (CIS) database for feeder 7075, which serves 2 000 customers with a total load of 4 MW. In this example, Circuit 7075 constitutes the "system" for which the indices are calculated. More typically, the "system" combines all circuits together in a region or for a whole company.

Table 4—Interruption data for 1994

Date	Time	Time on	Circuit	Event code	Number of customers	Load kVA	Interruption type
Mar 17	12:12:20	12:20:30	7075	107	200	800	S
Apr 15	18:23:56	18:24:26	7075	256	400	1 600	M
May 5	00:23:10	01:34:29	7075	435	600	1 800	S
Jun 12	23:17:00	23:47:14	7075	567	25	75	S
Jul 6	09:30:10	09:31:10	7075	678	2 000	4 000	M
Aug 20	15:45:39	20:12:50	7075	832	90	500	S
Aug 31	08:20:00	10:20:00	7075	1 003	700	2 100	S
Sep 3	17:10:00	17:20:00	7075	1 100	1 500	3 000	S
Oct 27	10:15:00	10:55:00	7075	1 356	100	200	S

NOTE 1—Interruption type S = sustained; M = momentary

NOTE 2—Total customers served = 2 000

The total number of customers who have experienced a sustained interruption is 3 215. The total number of customers experiencing a momentary interruption is 2 400.

Table 5—Extracted customers who were interrupted

Name	Circuit number	Date	Event code	Duration (min)
Willis, J.	7075	Mar 17, 1994	107	8.17
Williams, J.	7075	Apr 15, 1994	256	0.5
Willis, J.	7075	Apr 15, 1994	256	0.5
Wilson, D.	7075	May 5, 1994	435	71.3
Willis, J.	7075	Jun 12, 1994	567	30.3
Willis, J.	7075	Aug 20, 1994	832	267.2
Wilson, D.	7075	Aug 20, 1994	832	267.2
Yattaw, S.	7075	Aug 20, 1994	832	267.2
Willis, J.	7075	Aug 31, 1994	1003	120
Willis, J.	7075	Sep 3, 1994	1100	10
Willis, J.	7075	Oct 27, 1994	1356	40

Table 6—Interruption device operations

Record number	Device	Date	Time	Number of operations	Number of operations to lockout
1	Brk 7075	Apr 15	18:23:56	2	3
2	Recl 7075	Jul 6	09:30:10	3	4
3	Brk 7075	Aug 2	12:29:02	1	3
4	Brk 7075	Aug 2	12:30:50	2	3
5	Recl 7075	Aug 2	13:25:40	2	4
6	Recl 7075	Aug 25	08:00:00	2	4
7	Brk 7075	Sep 2	04:06:53	2	3
8	Recl 7075	Sep 5	11:53:22	3	4
9	Brk 7075	Sep 8	15:25:10	1	3
10	Recl 7075	Oct 2	17:15:19	1	4
11	Recl 7075	Nov 12	00:00:05	1	4

From Table 6, it can be seen that there were eight circuit breaker operations that affected 2 000 customers. Each of them experienced eight momentary interruptions. There were 12 recloser operations that caused 750 customers to experience 12 momentary interruptions. Some of the operations occurred during one reclosing sequence. To calculate the number of momentary interruption events, count only the total number of reclosing sequences. In this case, there were five circuit breaker events (records 1, 3, 4, 7, and 9) that affected 2 000 customers. Each of them experienced five momentary interruption events. There were six recloser events (records 2, 5, 6, 8, 10, and 11) that affected 750 customers, and each of them experienced six momentary interruption events.

4.2 Calculation of indices for a system with no Major Event Days

The equations in 3.5, and definitions in Clause 2, should be used to calculate the annual indices (see Eq. (33) through Eq. (46), below). In the example below, the indices are calculated by using the equations in 3.2 and 3.4 using the data in Table 4 and Table 5, assuming there were no MEDs in this data set.

$$\text{SAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{2000} = 1.61 \tag{33}$$

$$\text{SAIDI} = \frac{(8.17 \times 200) + (71.3 \times 600) + (30.3 \times 25) + (267.2 \times 90) + (120 \times 700) + (10 \times 1500) + (40 \times 100)}{2000} = 86.11 \text{ min} \tag{34}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{86.110}{1.6075} = 53.57\text{min} \tag{35}$$

To calculate CTAIDI and CAIFI, the number of customers experiencing a sustained interruption is required. The total number of customers affected (CN) for this example can be no more than 2 000. Since only a small portion of the customer information table is shown, it is impossible to know CN; however, it is likely that not all of the 2 000 customers on this feeder experienced an interruption during the year. An arbitrary number of customers, 1 800, will be assumed for CN (for your calculations, actual information should be used) since the interruption on September 3 shows that at least 1 500 customers have been interrupted during the year.

$$\text{CTAIDI} = \frac{(8.17\times 200)+(71.3\times 600)+(30.3\times 25)+(267.2\times 90)+(120\times 700)+(10\times 1500)+(40\times 100)}{1800} = 95.68\,\text{min} \tag{36}$$

$$\text{CAIFI} = \frac{200+600+25+90+700+1500+100}{1800} = 1.79 \tag{37}$$

$$\text{ASAI} = \frac{8760\times 2000-(8.17\times 200+600\times 71.3+30.3\times 25+267.2\times 90+120\times 700+10\times 700+10\times 1500+40\times 100)/60}{8760\times 2000} = 0.999836 \tag{38}$$

$$\text{ASIFI} = \frac{800+1800+75+500+2100+3000+200}{4000} = 2.12 \tag{39}$$

$$\text{ASIDI} = \frac{(800\times 8.17)+(1800\times 71.3)+(75\times 30.3)+(500\times 267.2)+(2100\times 700)+3000(6)+200\times 40}{4000} = 444.69 \tag{40}$$

CTAIDI, CAIFI, CEMI_n, CELID-s, CELID-t, and CEMSMI_n require detailed interruption information for each customer. The database should be searched for all customers who have experienced more than *n* interruptions that last longer than five minutes. Assume *n* is chosen to be five. In Table 5, customer J. Willis experienced seven interruptions in one year, and it is plausible that other customers also experienced more than five interruptions, both momentary and sustained.

For this example, assume arbitrary values of 350 for $CN_{(k\geq n)}$, 90 for $CN_{(k\geq S)}$, 40 for $CN_{(k\geq T)}$, and 750 for $CNT_{(k\geq n)}$. The number of interrupting device operations is given in Table 6 and is used to calculate MAIFI and MAIFI_E. Assume the number of customers downstream of the recloser equals 750. These numbers would be known in a real system.

$$\text{CEMI}_5 = \frac{350}{2000} = 0.175 \tag{41}$$

$$\text{CELID-s(4)} = \frac{90}{2000} = 0.045 \tag{42}$$

$$\text{CELID-t(6)} = \frac{40}{2000} = 0.02 \tag{43}$$

$$\text{MAIFI} = \frac{8\times 2000+12\times 750}{2000} = 12.5 \tag{44}$$

$$\text{MAIFI}_E = \frac{5\times 2000+6\times 750}{2000} = 7.25 \tag{45}$$

$$\text{CEMSMI}_5 = \frac{750}{2000} = 0.375 \tag{46}$$

Using the above sample system should help define the methodology and approach to obtaining data from the information systems and help calculate the indices.

4.3 Examples

This subclause illustrates two concepts—momentary interruptions and step restoration—through the use of examples.

4.3.1 Momentary interruption example

To better illustrate the concepts of momentary interruptions and sustained interruptions and the associated indices, consider Figure 1 and Eq. (45) through Eq. (47). Figure 1 illustrates a circuit composed of a circuit breaker (B), a recloser (R), and a sectionalizer (S).

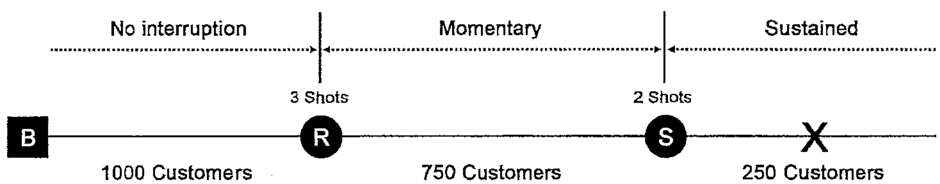

Figure 1—Sample system two

For this scenario, 750 customers would experience a momentary interruption event (two momentary interruptions), and 250 customers would experience a sustained interruption. Calculations for SAIFI, MAIFI, and $MAIFI_E$ on a feeder basis are shown in Eq. (47) through Eq. (49) below. Notice that the numerator of MAIFI is multiplied by two because the recloser took two shots, however, $MAIFI_E$ is multiplied by one because it counts only the fact that a series of momentary events occurred.

$$SAIFI = \frac{250}{2000} = 0.125 \tag{47}$$

$$MAIFI = \frac{2 \times 750}{2000} = 0.75 \tag{48}$$

$$MAIFI_E = \frac{1 \times 750}{2000} = 0.375 \tag{49}$$

4.3.2 Step restoration 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. Table 7 shows the times of each step, a description and associated customers interrupted, and minutes they were affected in a timeline format.

Table 7—Example for a feeder serving 1 000 customers with a sustained interruption

Time from initial fault (min)	Description	Customers remaining interrupted	Customers restored
—	The initial fault occurs, the feeder breaker opens, and all 1 000 customers are interrupted. Switches are opened along the feeder.	1 000	—
45	The feeder breaker is closed, but only 500 customers are restored.	500	500
60	Through closing a switch, an additional 300 customers are restored.	200	800
70	An additional incident occurs which causes the feeder breaker to open, interrupting the 800 customers previously restored.	1 000	—
90	The feeder breaker is closed, and restores 800 customers.	200	800
120	Permanent repairs are completed and the remaining 200 customers are restored. The outage event is concluded.	—	1 000
Totals		N/A	1 800

Figure 2 illustrates the example described in Table 7. Note that both the block of 500 customers and the block of 300 customers experience two interruptions during this event.

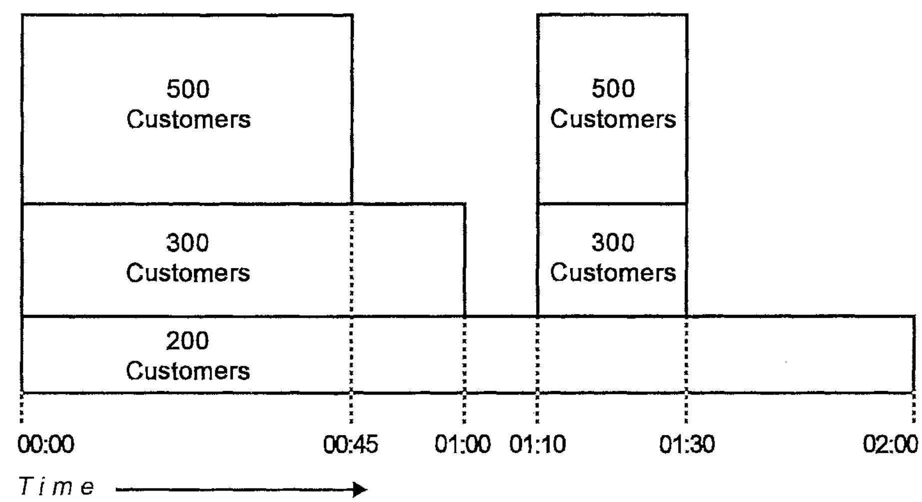

Figure 2—Step restoration time chart

Table 8 enumerates the CI and CMI for the example.

Table 8—Restoration steps for the example

Time	Interruption duration (min)	CI	CMI
00:00-00:45	45	500	22 500
00:00-01:00	60	300	18 000
01:10-01:30	20	800	16 000
00:00-02:00	120	200	24 000
	Total	1 800	80 500

Example SAIFI = 1 800/1 000 = 1.8 interruptions

Example CAIDI = 80 500/1 800 = 44.7 min

Example SAIDI = 80 500/1 000 = 80.5 min

5. Information about the factors that affect the calculation of reliability indices

5.1 Rationale behind selecting the indices provided in this guide

One view of distribution system performance can be garnered through the use of reliability indices. To adequately measure performance, both duration and frequency of customer interruptions must be examined at various system levels. The most commonly used indices are SAIFI, SAIDI, CAIDI, and ASAI, which all provide information about average system performance. Many utilities also calculate indices on a feeder basis to provide more detailed information for decision making. Averages give general performance trends for the utility; however, using averages will lead to loss of detail that could be critical to decision making. For example, using system averages alone will not provide information about the interruption duration experienced by any specific customer. It is difficult for most utilities to provide information on a customer basis. This group believes the tracking of specific details surrounding interruptions, rather than averages, may be accomplished by improving tracking capabilities. To this end, the working group has included not only the most commonly used indices, but also indices that examine performance at the customer level (e.g., $CEMI_n$ and the CELIDs).

5.2 Factors that cause variation in reported indices

Many factors can cause variation in the indices reported by different utilities. Some examples are differences in:

- Level of automated data collection
- Geography
- System design
- Data classification (e.g., Are major events in the data set? Planned interruptions?)

To ensure accurate and equitable assessment and comparison of absolute performance and performance trends over time, it is important to classify performance for each day in the data set to be analyzed as either day-to-day or MED. Not performing this critical step can lead to false decision making because MED performance often overshadows and disguises daily performance. Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in the index calculation.

5.3 Major Event Days and catastrophic days

When using daily SAIDI and the 2.5β method, there is an assumption that the distribution of the natural log values will most likely resemble a Gaussian distribution, namely a bell-shaped curve. As companies have used this method, a certain number of them have experienced large-scale events (such as hurricanes or ice storms) that result in unusually sizable daily SAIDI values. The events that give rise to these particular days, considered "catastrophic events," have a low probability of occurring. However, the extremely large daily SAIDI values may tend to skew the distribution of performance toward the right, causing a shift of the average of the data set and an increase in its standard deviation. Large daily SAIDI values caused by catastrophic events will exist in the data set for five years and could cause a relatively minor upward shift in the resulting reliability metric trends. While significant study was undertaken to develop objective methods for identifying and processing catastrophic events (in order to eliminate the noted effect on the reliability trend), the methods that were developed, in order to be universally applied, caused for many

utilities, catastrophic events to occur far too often to accept as being reasonable. In addition, the elimination of catastrophic events from the calculation of the major event threshold caused, in some utilities, a rather large increase of days identified as MEDs in the following five years. It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results.

Annex A

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

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Annex B

(informative)

Major event definition development

B.1 Justification and process for development of the 2.5 β methodology

A statistical approach to identifying MEDs was chosen over the previous definitions because of the difficulties experienced in creating a uniform list of types of major events, and because the measure of impact criterion (i.e., percent of customers affected) required when using event types resulted in non-uniform identification. The statistical methodology should more fairly identify major events for all utilities. Some key issues had to be addressed in order to consider this work successful. These issues include:

- Definition must be understandable and easy to apply.
- Definition must be specific and calculated using the same process for all utilities.
- Must be fair to all utilities regardless of size, geography, or design.
- Entities that adopt the methodology will calculate indices on a normalized basis for trending and reporting. They will further classify the MEDs separately and report on those days through a separate process.

Daily SAIDI values are preferred to daily Customer Minutes of Interruption (CMI) values for MED identification because the former permits comparison and computation among years with different numbers of customers served. Consider the merger of two utilities with the same reliability and the same number of customers. CMI after the merger would double, with no change in reliability, while SAIDI would stay constant.

Daily SAIDI values are preferred to daily SAIFI values because SAIDI values are a better measure of the total cost of reliability events, including utility repair costs and customer losses. The total cost of unreliability would be a better measure of the size of a major event, but collection of this data is not practical.

The selected approach for setting the MED identification threshold, known as the "Two Point Five Beta" (2.5β) method (since it is using the log-normal SAIDI values rather than the raw SAIDI values), is preferred to using fixed multiples of standard deviation (e.g., "Three Sigma") to set the identification threshold because the former results in more uniform MED identification among utilities with different sizes and average reliabilities. The β multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability. The process and the multiplier value were evaluated by a number of utilities with different sized systems from different parts of the United States and found to correlate reasonably well to current major event identification results for those utilities. A number of alternative approaches were considered. None was found to be clearly superior to the 2.5β method.

When a major event occurs that lasts through midnight (for example, a six hour hurricane which starts at 9:00 p.m.), the reliability impact of the event may be split between two days, neither of which would exceed the T_{MED} and therefore be classified as a MED. This is a known inaccuracy in the method, which is accepted in exchange for the simplicity and ease of calculation of the method. The preferred number of years of data (five) used to calculate the MED identification threshold was set by trading off between the desire to reduce statistical variation in the threshold (for which more data is better) and the desire to see the effects of changes in reliability practices in the reported results, and to limit the amount of data which must be archived.

B.1.1 Remarks

To generate the example data used in 3.5.1, values of α and β were taken from an actual utility data set, and then daily SAIDI/day values were artificially generated using a log normal distribution with these values of α and β. The daily SAIDI values were then adjusted to illustrate all aspects of the calculation (e.g., a day in Table 2 was assigned a SAIDI value of zero, and a day in Table 3 was assigned a SAIDI value higher than the computed threshold).

This annex provides a technical description and analysis of the 2.5β method of identifying MEDs in distribution reliability data. The 2.5β method is a statistical method based on the theory of probability and statistics. Fundamental concepts such as *probability distribution* and *expected value* are highlighted in italics when they are first used and provided with a short definition. An undergraduate probability and statistics textbook can be consulted for definitions that are more complete.

B.2 2.5β method description

See 3.5 of this guide for the detailed procedure for identifying MEDs. The short version is presented here. A threshold on daily SAIDI is computed once a year as follows:

a) Assemble the five most recent years of historical values of SAIDI/day. If less than five years of data is available, use as much as is available.

b) Discard any day in the data set that has a SAIDI/Day of zero.

c) Find the natural logarithm of each value in the data set.

d) Compute the average (α, or Alpha) and standard deviation (β or Beta) of the natural logarithms computed in step a).

e) Compute the threshold $T_{MED} = \exp(\alpha + 2.5 * \beta)$.

f) Any day in the next year with SAIDI > T_{MED} is a MED.

B.3 Random nature of distribution reliability

The reliability of electric power distribution systems is a *random process*, that is, a process that produces random values of a specific *random variable*. A simple example of a random process is rolling a die. The random variable is the value on the top face of the die after a roll, which can have integer values between one and six.

In electric power distribution system reliability, the random variables are the reliability indices defined in this guide. These are evaluated on a daily or yearly basis and take on values from zero to infinity.

B.4 Choice of SAIDI to identify Major Event Days

Four commonly used reliability indices are:

a) System Average Interruption Duration Index (SAIDI)

b) System Average Interruption Frequency Index (SAIFI)

c) Customer Average Interruption Duration Index (CAIDI)

d) Average Service Availability Index (ASAI)

These indices are actually measures of unreliability, as they increase when reliability becomes worse.

An ideal measure of unreliability would be customer cost of unreliability—the dollar cost of power outages to a utility's customers. This cost is a combination of the initial cost of an outage and accumulated costs during the outage. Unfortunately, the customer cost of unreliability has so far proven impossible to estimate accurately. In contrast, the reliability indices above are routinely and accurately computed from historical reliability data. The ability of an index to reflect customer cost of unreliability indicates the best one to use for MED identification.

Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore, SAIDI best reflects the customer cost of unreliability, and is the index used to identify MEDs. SAIDI in minutes/day is the random variable used for MED identification.

The use of CMI per day was also considered. Like SAIDI, CMI is a good representation of customer cost of unreliability. In fact, SAIDI is just CMI divided by the number of customers in the utility. The number of customers can vary from year to year, especially in the case of mergers, and multiple years of data are used to find MEDs. Use of SAIDI accounts for the variation in customer count, while use of CMI does not. Therefore, SAIDI is preferred.

B.5 Probability distribution of distribution system reliability

B.5.1 Probability density functions and probability of exceeding a threshold value

MEDs will be days with larger SAIDI values. This suggests the use of a threshold value for daily SAIDI. The threshold value is called T_{MED}. Days with SAIDI greater than T_{MED} are MEDs. As the threshold increases, there will be fewer days with SAIDI values above the threshold. The relationship between the threshold and the number of days with SAIDI above the threshold is given by the *probability density function* of SAIDI/day.

The probability density function gives the probability that a specific value of a random variable will appear. For example, for a six-sided die, the probability that a one will appear in a given roll is one-sixth, and the value of the probability density function of one is one-sixth for this random process.

The probability that a value greater than one will occur is the sum of the probability densities for all values greater than one. Since each value has a probability density of one-sixth for the example, this sum is simply five-sixths. As the threshold increases, the probability decreases. For example, for a threshold of four, there are only two values greater than four, and the probability of rolling one of them is two-sixths, or one-third.

In the die rolling example, the random variable can have only discrete integer values. SAIDI/day is a continuous variable. In this case, the sum is replaced by an integral. The probability p that any given day will have a SAIDI/day value greater than a threshold value T is the integral of the probability density function from the threshold to infinity as shown in Eq. (B.1):

$$p(\mathrm{SAIDI} > T) = \int_T^{\infty} pdf(\mathrm{SAIDI})\,d\mathrm{SAIDI} \tag{B.1}$$

Graphically, the probability is the area under the probability density function above the threshold, as shown in Figure B.1.

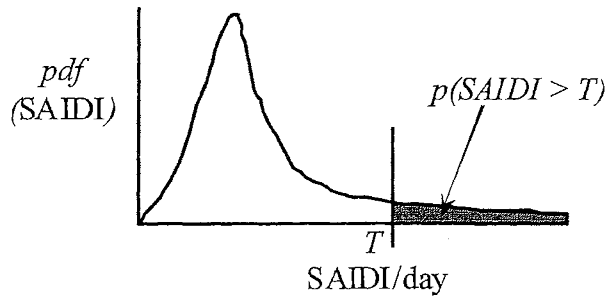

Figure B.1—The area under the probability density of function pdf (SAIDI)

If any given day has a probability *p* of being a MED, then the *expected value* [see Eq. (B.2)] of the number of MEDs in a year is the probability multiplied by the number of days in a year, as shown in Eq. (B.2):

$$E(MED/year) = 365 \cdot p(\mathrm{SAIDI} > T_{MED}) \tag{B.2}$$

For example, if p = 0.1, then the expected number of MEDs in a year is 36.5. This does not mean that exactly 36.5 MEDs will occur. The actual number will vary due to the randomness of the process.

Using the die rolling example, the probability of getting a six in any roll is one-sixth. Therefore, the expected number of sixes in six rolls is one. However, if the die is rolled six times, there could be six sixes, or zero sixes, or any number in between. As the number of trials goes up, the number of sixes will approach one-sixth of the number of rolls, but for small numbers of rolls, there will be some variation from the expected value.

B.5.2 Gaussian, or normal, distribution

The expected number of MEDs per year can be computed for any given threshold if the shape of the probability density function is known. The shape of the probability density function is called the *probability distribution*. Specific types of shapes have specific names. The most well known is the *Gaussian distribution*, also called the *normal distribution*, or bell curve, shown in Figure B.2.

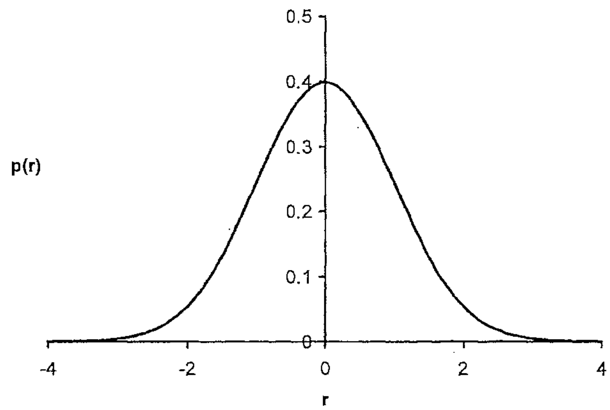

Figure B.2—Gaussian, or normal, probability distribution

The Gaussian distribution is completely described by its *mean*, or average value, (μ or Mu) and its *standard deviation* (σ or Sigma). The average value is at the center of the distribution (at 0 on the *x*-axis in Figure B.2), and the standard deviation is a measure of the spread of the distribution.

An important property of the Gaussian distribution is that the probability of exceeding a given threshold is a function of the number of standard deviations the threshold is from the mean. Eq. (B.3) expresses this concept in mathematical terms:

$$T_{MED} = \mu + n\sigma \tag{B.3}$$

The threshold is n standard deviations greater than the mean, and the probability of exceeding the threshold, $p(\text{SAIDI} > T_{MED})$, is a function only of n, and not of the mean and standard deviation. Values for this function are found in tables in the backs of probability textbooks and in, for example, standard spreadsheet functions. Table B.1 gives the probability of exceeding the threshold for different number of standard deviations n.

Table B.1—Probability of exceeding a threshold for the Gaussian distribution

n	p
1	0.15866
2	0.02275
3	0.00135
6	9.9×10^{-10}

B.5.3 Three sigma

The term *three sigma* is often used loosely to designate a rare event. It comes from the Gaussian probability distribution. As Table B.1 shows, the probability of exceeding a threshold that is three standard deviations more than the mean is 0.00135, or about one and one-half tenths of one percent. If daily SAIDI had a Gaussian probability distribution, it would be relatively easy to agree on a three sigma definition for the MED threshold, T_{MED}. SAIDI does not have a Gaussian distribution. It has approximately a log-normal distribution.

B.6 Log-normal distribution

The random variable in the Gaussian distribution has a range from -∞ to ∞. In real life, many quantities, including distribution reliability, can only be zero or positive. This causes the probability distribution to skew, bunching up near the zero value and having a long tail to the right. The degree of skew depends on the ratio of mean to standard deviation. When the standard deviation is small compared to the mean, the log-normal distribution looks like the Gaussian distribution, as shown in Figure B.3(b). When it is large compared to the mean, it does not, as shown in Figure B.3(a). Daily reliability data usually has standard deviation values far larger than the mean.

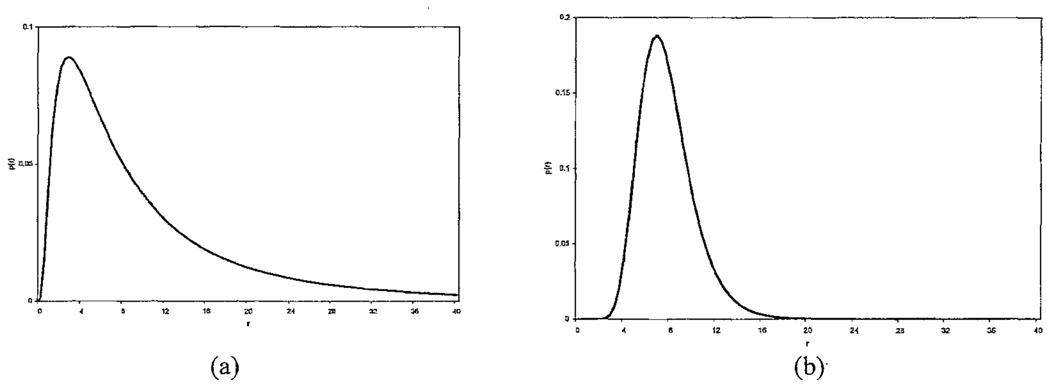

Figure B.3—Log-normal distributions: (a) Mean less than standard deviation (b) Mean greater than standard deviation

The usual way of determining if a set of data has a log-normal probability distribution is to take the natural logarithm of each value in the data set and examine the histogram. If the histogram looks like a Gaussian distribution, then the data has a log-normal distribution. Figure B.4 shows a histogram of the natural logs of daily SAIDI data for an anonymous utility. The histogram is approximately normally distributed, so the data is approximately log-normally distributed. Roughly a dozen utility data sets have been examined, and all are approximately log-normally distributed. No non-log-normally distributed utility data has so far been found. In addition, Monte Carlo simulation models of the distribution reliability process produce log-normally distributed data. Therefore, utility daily reliability is approximately log-normally distributed.

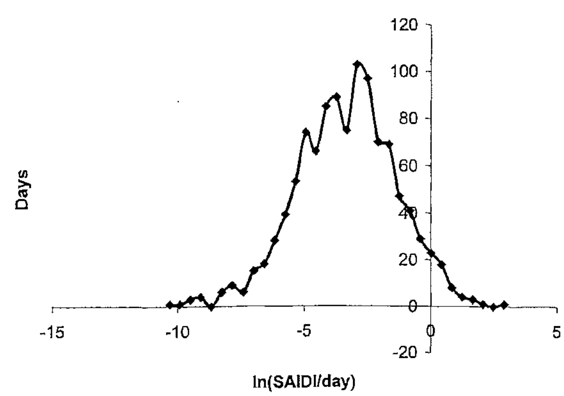

Figure B.4—Histogram of the natural logs of three years of daily SAIDI data from anonymous utility two supplied by the Distribution System Design Working Group

A consequence of the log-normality of daily reliability data is that the three sigma conditions no longer hold. In particular, the probability of exceeding a given threshold is no longer independent of the values of the average and standard deviation of the distribution. This means that using a method such as three sigma would result in significantly different numbers of MEDs for utilities with different average values of reliability, or with different standard deviation values. This seems inequitable.

Fortunately, the logarithms of log-normal data have a Gaussian distribution. If the average of the logarithms of the data is called α, or Alpha, and the standard deviation of the logarithms of the data is called β, or Beta, then α and β are the mean and standard deviation of a Gaussian distribution, and a threshold on the log of the data can be set that is independent of the values of α and β. Eq. (B.4) and Eq. (B.5) show these concepts mathematically.

$$\ln(T_{MED}) = \alpha + k\beta \tag{B.4}$$

$$T_{MED} = \exp(\alpha + k\beta) \tag{B.5}$$

The probability of exceeding T_{MED} is a function of k, just as it was a function of n in the Gaussian example. Table B.2 gives these probabilities as well as the expected number of MEDs for various values of k.

Table B.2—Probability of exceeding T_{MED} as a function of multiples of β

k	p	MEDs/yr
1	0.15866	57.9
2	0.02275	8.3
2.4	0.00822	3.0
2.5	0.00621	2.3
3	0.00135	0.5
6	9.9×10^{-10}	3.6E-07

B.6.1 Why 2.5?

Given an allowed number of MEDs per year, a value for k is easily computed. However, there is no analytical method of choosing an allowed number of MEDs/year. The chosen value of $k = 2.5$ is based on consensus reached among Distribution Reliability Working Group members on the appropriate number of days that should be classified as MEDs. As Table B.2 shows, the expected number of days for $k = 2.5$ is 2.3 MEDs/year. In practice, the experience of the committee members, representing a wide range of distribution utilities, was that more than 2.3 days were usually classified as MEDs, but that the days that were classified as MEDs were generally those that would have been chosen on qualitative grounds. The performance of different values of k were examined, and consensus was reached on $k = 2.5$.

B.7 Fairness of the 2.5β method

It is likely that reliability data from different utilities will be compared by utility management, public utilities commissions, and other interested parties. A fair MED classification method would classify, on average, the same number of MEDs per year for different utilities.

The two basic ways that utilities can differ in reliability terms are in the mean and standard deviation of their reliability data. Differences in means are attributable to differences in the environment between utilities, and differences in operating and maintenance practices. Differences in standard deviation are mostly attributable to size. Larger utilities have inherently smaller standard deviations.

As discussed above, using the mean and standard deviation of the logs of the data (α and β) to set the threshold makes the expected number of MEDs depend only on the multiplier and thus should classify the same number of MEDs for large and small utilities, and for utilities with low and high average reliability.

This is not the case for using the mean and standard deviation of the data without taking logarithms first. The expected number of MEDs varies with the mean and standard deviation. This variation occurs because of the log-normal nature of the reliability probability distribution.

Experience with the 2.5β method has shown that it is better than using mean and standard deviation, but it is not perfect. The number of MEDs identified per year is significantly higher than expected, and the average number of MEDs varies somewhat from utility to utility, with size affecting the value. These effects appear because the probability distribution of distribution system reliability is only approximately log-normal. Significant differences appear in the right hand tail of the distribution, which in general contains more probability than a perfect log-normal distribution. This "fat tail" effect accounts for the larger-than-predicted number of identified MEDs. The effect of utility size is less clearly understood.

Despite these issues, the 2.5β method of MED identification is much closer to the ideal fair process than using a Gaussian distribution, using the heuristic definitions that preceded it, or any other method proposed to date. It has been carefully tested and has been broadly accepted by the utilities in the Distribution Design Working Group and many other utilities and regulators that have adopted this guide.

B.8 Five years of data

From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes.

The addition of another year of data should have a low probability of changing the MED classification of previous years. A result from order statistics gives the probability that the kth largest value in m samples will be exceeded f times in n future samples. It is given in Eq. (B.6):

$$p_{f|m,k,n} = \frac{k}{n+k-f} \frac{\binom{m}{k}\binom{n}{f}}{\binom{n+m}{n+k-f}} \tag{B.6}$$

For example, if $M = 3$ years of data, then $m = 1\,095$ samples. If $f = 3$ MEDs/year, then the largest non-MED is the $k = 1\,095 - 9 = 1\,086^{\text{th}}$ ordered sample. The probability of $f = 3$ days in the next year of $n = 365$ samples exceeding the size of the largest non-MED is found from the equation to be 0.194 (19.4%). In Figure B.5, p is plotted against M for several values of f.

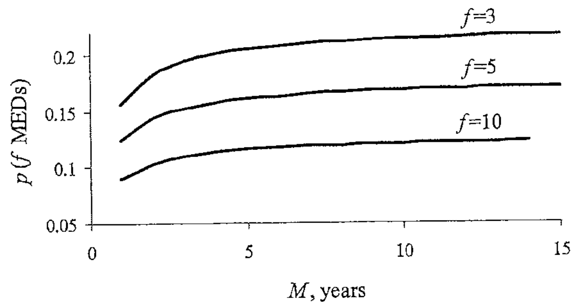

Figure B.5—Probability of exactly *f* new MEDs in the next year of data using *M* years of historical data

The consensus of the Design Working Group members was that five years was the appropriate amount of data to collect. The group felt that the distribution system would change enough to invalidate any extra accuracy from more than five years of data.

Annex C

(informative)

Internal data subset

C.1 Calculation of reliability indices for subsets of data for internal company use

Reliability performance can be assessed for different purposes. It may be advantageous to calculate reliability indices without planned interruptions in order to review performance during unplanned events. In another case, it may be advantageous to review only sustained interruptions. Assessment of performance trends and goal setting should be based on normal event days (neglecting the impact of MEDs). Utilities and regulators determine the most appropriate data to use for reliability performance monitoring. When indices are calculated using partial data sets, the basis should be clearly defined for the users of the indices. At a minimum, reliability indices based on all collected data for a reporting period and analyzed as to normal versus MED classifications should be provided. Indices based on subsets of collected data may be provided as specific needs dictate.

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