GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: NOTICE OF NONCOMPLIANCE WITH THE PUERTO RICO ENERGY PUBLIC POLICY	**CASE NO. NEPR-AI-2025-0001** **SUBJECT: LUMA's Response to Order on Noncompliance with SAIDI Metric, and Request for a Hearing**

MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER OF FEBRUARY 11, 2025, AND REQUEST FOR A HEARING

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COME now **LUMA Energy, LLC** ("ManageCo") and **LUMA Energy ServCo, LLC** ("ServCo"), (jointly "LUMA"), and respectfully state and request the following:

I. Introduction

On February 11, 2025, the Honorable Puerto Rico Energy Bureau ("Energy Bureau" or "Bureau") issued a Resolution and Order opening the instant proceeding ("February 11th Order"). Therein, the Energy Bureau referred to reports submitted by LUMA to the Energy Bureau and to a performance analysis conducted by that regulatory body, alleging a failure by LUMA to improve reliability and meet the established SAIDI[1] metric benchmark. According to the February 11th Order, the SAIDI value for the combined transmission and distribution system ("T&D System") for Fiscal Year 2024 ("FY24") is higher than both the SAIDI value reported for Fiscal Year 2023 ("FY23"), and the Fiscal Year 2020 ("FY20") baseline established by the Energy Bureau, "indicating an increase in the average duration of service interruptions and/or reflecting longer

[1] System Average Interruption Duration Index.

service outages." *See* February 11th Order, at p. 2. Through the February 11th Order, the Energy Bureau informed LUMA of the issuance of a Notice of Noncompliance to ensure corrective action. It cautioned that a fine -more likely in the amount of $1.825 million- is necessary to counteract the negative trend in outage duration and to ensure compliance with performance standards.[2] LUMA respectfully submits this response in compliance with the February 11th Order.

Since taking over the operation and maintenance of the T&D System[3], LUMA has steadfastly worked to improve reliability and resiliency, launching numerous strategic initiatives designed to elevate service quality, minimize outage duration, and improve the overall robustness of the grid infrastructure, notwithstanding significant budget constraints. To that end, since it commenced to operate and maintain the T&D System, LUMA has managed to invest efficiently and prudently to execute programmatic initiatives to improve reliability, as described in detail in **Exhibit 1** of this Motion, "LUMA's Response to February 11, 2025, Resolution and Order" ("LUMA's Response"). *See* **Exhibit 1**, at p. 1.

As ordered by the Energy Bureau, LUMA's Response provides detailed information on the direct and indirect root causes of FY24 SAIDI performance, from an operational perspective. It also summarizes the corrective action plan that LUMA is implementing to improve the SAIDI value and prevent further deterioration, along with timelines for the implementation of each workstream.

Further, LUMA retained the services of expert consultant Exponent, Inc. ("Exponent" or "Expert") to perform an independent assessment of LUMA's reliability performance and address

---

[2] According to the February 11th Order, the Energy Bureau is "inclined" to impose LUMA a fine in such amount considering the extent of deviation from established standards, the duration of noncompliance, and the impact on consumers. See February 11th Order, at pp. 2-3.

[3] See *Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement* ("T&D OMA") executed on June 22, 2020, by and between LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public Private Partnerships Authority, as administrator.

the root causes of LUMA's alleged noncompliance and any mitigating factors. Exponent conducted a comprehensive analysis of the Interruption Database to identify the underlying factors leading to the reported SAIDI value for FY24. The outage data that was reviewed, was first collected by PREPA from FY2019 through FY2021 ("PREPA Years"), and then by LUMA from FY2022 onwards ("LUMA Years"). The outage data provides raw data for every outage event, such as start time, end time, cause code, CI[4], and the associated CMI[5]. As explained in Exponent's report (the "Expert Report"), a copy of which is attached herewith as **Exhibit 2**, comparing the SAIDI value for FY24 with the SAIDI value for FY23 is not necessarily representative of a decline in system reliability, given the exclusion of major event days (37 in total) from the reliability calculations in FY23 due to Hurricane Fiona[6], as per IEEE Standard 1366-2012[7].

Moreover, comparing the SAIDI value for FY24 with the baseline of FY20 is misleading for two main reasons. First, PREPA's data collection practices caused SAIDI-reported values to be artificially low. Second, there was an increase in the frequency of non-excluded weather events[8] in FY24, in contrast with FY20, which was a relatively mild year in terms of storms. As explained in more detail in LUMA's Response, "in FY24, LUMA observed a notable CMI contribution of more than 6% on SAIDI due to adverse weather conditions (Weather and Lightning categories), resulting in prolonged outages…."[9] *See* **Exhibit 1**, at p. 6. Moreover, as explained by the Expert, extreme weather conditions in FY24, such as increased temperatures and significant rainfall,

[4] Customers Interrupted, which is used to measure the number of customers affected by a power outage.
[5] Customer Minutes of Interruption, meaning the total number of minutes that customers experienced power outages during a specific period.
[6] Hurricane Fiona made landfall in Puerto Rico as a category 1 storm on September 18, 2022.
[7] LUMA reports reliability metrics, including SAIDI, in accordance with the IEEE Guide for Electric Power Distribution Reliability Indices (IEEE Standard 1366-2012).
[8] As said term is defined hereinbelow.
[9] Adding that "weather related factors such as heavy rain, strong winds, and frequent lightning strikes caused significant infrastructure damage, including downed power lines, broken poles, and malfunction equipment. These conditions not only extended restoration times but also required extensive efforts from crews to repair or replace damaged components…."

directly impacted vegetation growth and system loading, resulting in higher numbers of outages due to vegetation and equipment overloading.

As will be discussed in this Motion, the Expert's findings clearly show that (i) the SAIDI values during the LUMA Years (FY22 through FY24) have stayed essentially constant if the major event days associated with Hurricane Fiona are properly considered; (ii) after adjusting the reported SAIDI value for FY23 to account for the Hurricane Fiona major event days, the reported SAIDI value for FY24 shows only a slight increase of 3.8% when compared to FY23; and (iii) a comparison of the reported SAIDI value for FY24 to the benchmark year of FY20 is misleading for various reasons. First, during the PREPA Years, PREPA did not record a significant number of outages, making its reported SAIDI artificially low. Second, weather severity in FY20 was mild when directly compared to FY24. Third, LUMA has implemented safety protocols that result in increased average SAIDI but should not be penalized for taking proactive steps to ensure safety.

In view of the foregoing reasons, LUMA respectfully submits that the February 11th Order should be vacated outright, as the expert evidence clearly demonstrates that the Energy Bureau's conclusion of worsening in reliability for FY24 is unfounded. The notice of noncompliance and the finding on the imposition of a penalty are unwarranted.

In addition, LUMA contends that the February 11th Order violates its due process rights because it states the Energy Bureau's manifested inclination to impose a significant fine upon LUMA, based on a "performance analysis" that is not found on the record in both the instant proceeding and proceeding NEPR-MI-2019-0007 ("Case No. 0007"), and without following applicable law and regulations, and also contains factual and legal conclusions that confirm that the Energy Bureau already prejudged LUMA's alleged noncompliance and that a fine is justified. As further expanded upon in this Motion, the instant proceeding stems from LUMA's submission to the Energy Bureau of quarterly reports on the reporting Case No. 0007 containing certain information on the T&D System, including performance regarding certain metrics/indicators ("System Data"). The filings of quarterly System Data reports in Case No. 0007 are informative in nature and are an "ongoing process." *See* Resolution and Order of May 21st, 2021, at p. 15. Moreover, and although Case No. 0007 does not contemplate, as part of its objectives, the imposition of penalties or fines for the values reported for any given performance metric, nor does it have identified specific targets that LUMA must reach, the Energy Bureau opted to leverage the information in the quarterly reports to carry out an undisclosed analysis -the details of which are unknown to LUMA- and initiate a proceeding for non-compliance and the imposition of fines accordingly, upon reaching factual and legal conclusions without allowing LUMA to state its position. In doing so, the Energy Bureau violated LUMA's due process rights.

Lastly, the Energy Bureau has not adopted parameters to impose penalties for noncompliance with the baselines of a performance metric. Imposing fines on LUMA for performing in any given manner when parameters for noncompliance with the baselines of a performance metric have not been adopted nor implemented, results in a violation of LUMA's right to due process and may also lead to the imposition of fines that are either disproportionate or plainly unjustified, as in this case.

For these reasons, as further expanded upon hereinbelow, LUMA respectfully contends that the Energy Bureau should vacate the February 11th Order. In the alternative, LUMA respectfully submits that the Energy Bureau must convene a hearing, to allow for a more robust discussion of LUMA's performance under the SAIDI performance metric for FY24, and to assess the factors that justify the modification of the proposed fine, should the Energy Bureau insist that a fine is appropriate.

II. Procedural Background

Following the mandate in the *Puerto Rico Energy Transformation and RELIEF Act*, as amended, Act 57-2014 ("Act 57-2017"), on May 14, 2019, the Energy Bureau issued a Resolution and Order ("May 14th Order") initiating the proceedings in Case No. 0007, to gather information and establish performance metrics for the electric system in Puerto Rico, then operated entirely by PREPA. In accordance with "typical practices of the electric industry" in Puerto Rico, as well as in the United States, the metrics used to measure the performance and execution of electric service companies are generated by the regulated entity and reported to the regulator through quarterly or annual reports. Through the May 14th Order, the Energy Bureau ordered PREPA to submit quarterly reports starting September 15, 2019.

On June 22, 2020, LUMA, PREPA, and the P3A entered into the T&D OMA, whereby LUMA assumed the operation and maintenance of PREPA's T&D System, starting June 1st, 2021. Pursuant to Section 5.6 of the T&D OMA, LUMA, as an agent of PREPA, submits System Data regarding the T&D System.

On December 23, 2020, the Energy Bureau issued a Resolution and Order ("December 23rd Order"), starting the procedure to establish a Performance Baseline and Performance Compliance Benchmarks for the operation of PREPA's electric system. The Performance Baseline metrics measure the historical behavior of PREPA's performance regarding specific parameters and serve as a starting point for understanding the need for any improvement in the area. However, the Performance Compliance Benchmarks metrics result from a specific parameter, following the evaluation of the performance of eight (8) utilities comparable to PREPA, either by the number of customers or the geography of the service area. Meanwhile, on December 30, 2020, the Energy Bureau issued a Resolution and Order ("December 30th Order") ordering PREPA to present, every 20th day of the month after each quarter closes, the quarterly system reports.

In connection with the December 23rd Order and following a request made by the Energy Bureau during a prefiling conference held on January 19, 2021, on January 29th, 2021, LUMA filed a motion submitting *inter alia* comments on proposed performance metrics and performance baselines and an initial assessment and proposal of benchmarks on reliability performance (*i.e.*, SAIDI and SAIFI). Relevant to the instant case, the SAIDI value represents the total duration of interruption for an average customer over a given time period, typically a year. SAIDI is calculated by taking the sum of all customer interruption durations and dividing it by the total number of customers served.

Through the January 29th submission, LUMA questioned the accuracy of the reliability data reported by PREPA in light of the fact that (i) it did not include transmission or substation related outages or outages due to many of the causes listed in their Cause Code list for published reliability metrics; and (ii) the numbers were also calculated using an outdated Major Event Day threshold, which, relevant to the instant case, resulted in lower SAIDI numbers. LUMA argued that with transmission, substation, and distribution outages and all but generation and planned outages included, reliability metrics were exceptionally high, consistent with the physical deterioration of the grid over a long period. As for benchmarks and future trends of reliability, LUMA stated that the future trend of PREPA's reliability was worsening, adding that this trend was likely to continue until substantial and significant investments were made for a period of years.[10] LUMA reiterated these statements when it resubmitted its performance baselines and metrics comments to the Energy Bureau on February 5, 2021.[11]

[10] *See* "Motion Submitting LUMA's Comments on Performance Metrics Data Presented on January 19th, 2020, by the Energy Bureau and Submitting Proposed Performance Metrics and Baselines", filed by LUMA with the Energy Bureau on January 29, 2021, Exhibit 3, at pp. 5-8.

[11] *See* "Motion Resubmitting LUMA's Comments on Performance Baselines and Metrics based on Data Presented on January 19th, 2020 by the Energy Bureau, and Resubmitting Proposed Performance Metrics and Baselines", filed by LUMA with the Energy Bureau on February 5, 2021, Exhibit 3, at pp. 5-8.

Thereafter, on May 21, 2021, the Energy Bureau issued a Resolution and Order ("May 21st Order"), where it approved and established the baselines and benchmarks for the metrics and ordered PREPA and LUMA to coordinate the necessary logistics to file the quarterly reports. Relevant to the instant proceeding, the Energy Bureau adopted the then-most recent fiscal year ending June 30, 2020, as the baseline period for metrics and set the FY20 baseline and proposed benchmark for the SAIDI factor at 1,243 and 102 minutes, respectively.

On July 22, 2024, LUMA submitted System Data for the months of April through June 2024. On August 9, 2024, the Energy Bureau issued a Resolution and Order in Case No. 0007 with the Subject "Response to LUMA's Submission of Performance Metrics Report for April through June 2024" ("August 9th Order") determining that additional information was required to evaluate LUMA's FY24 performance and instructing LUMA to respond, within fourteen (14) calendar days, to that certain Request for Information ("RFI") enclosed as Exhibit A of the August 9th Order. Following a request for a brief extension, on August 30, 2024, LUMA filed a "Motion Submitting Response to the Request for Information Issued in the Resolution and Order of August 9, 2024", enclosing its responses to the RFI.

Thereafter, the Energy Bureau notified the February 11th Order in the instant proceeding, whereby it formally issued a Notice of Noncompliance to ensure corrective action, due to the worsening of the SAIDI value from 1,218 in FY23 to 1,432 in FY24, which also represents an increase from the FY20 baseline of 1,243. *See* February 11th Order, at p. 2. The Energy Bureau ordered LUMA to respond by providing the Bureau with (a) a Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent further deterioration of service quality, and (b) justification explaining the root causes of the noncompliance and any mitigation factors, which failure will result in the imposition of penalties, additional regulatory oversight or other actions deemed appropriate by the Energy Bureau. The February 11th Order also warned of the Energy Bureau's inclination to impose LUMA a fine of $1.825 million, calculated at $5,000.00 per day per 365 days/year.

On February 26, 2025, LUMA filed a "Request for Extension of Time to Comply with Resolution and Order of February 11, 2025," requesting that the February 11th Order be complied with until this date. The Energy Bureau granted said request on February 27, 2025.

On March 6, 2025, LUMA requested and was granted access to the Energy Bureau's administrative record for Case No. 0007. Upon review, LUMA could not locate the "performance analysis" alluded to by the Energy Bureau in the February 11th Order.

III. Discussion

A. The Expert Report shows that the reported SAIDI value for FY24, as interpreted by the Energy Bureau, does not accurately depict LUMA's reliability performance and, therefore, should not serve as a basis for the imposition of fines against LUMA.

1. It is improper for the Energy Bureau to compare LUMA's reported SAIDI values for FY24 with the SAIDI values for FY23 because of, among other things, the impact of Hurricane Fiona in FY23 in the calculation of SAIDI, wich resulted in the exclusion of major event days from the reliability calculation for FY23 in accordance with the standards in the industry.

According to the February 11th Order, the increase in the SAIDI value from FY23 to FY24 indicates worsening reliability. However, as explained in the Expert Report, an analysis of the T&D System data *shows that the SAIDI value has stayed essentially constant during the LUMA Years (i.e., 2022-2024)* if the major event days associated with Hurricane Fiona are properly considered.

As is known by the Energy Bureau, LUMA reports SAIDI values in accordance with the IEEE Guide for Electric Power Distribution Reliability Indices ("IEEE Standard 1366"). This standard includes a statistical methodology to identify major event days, which are days where the system's operational and/or design limits are exceeded.[12] Major event days are excluded when calculating reliability indices, as they can distort the normal performance of the system.

As explained in the Expert Report, a review of the T&D System data from FY19 to FY24 shows that, without including FY23, the number of major event days in a given fiscal year ranges from 2 to 9. Relevant to the instant proceeding, FY24 has a total of 5 major event days. In contrast, FY23 has a total of 39 major event days, of which 37 are attributable to Hurricane Fiona. *See* Expert Report, p. 8. Because, consistent with IEEE Standard 1366, major event days are excluded from the calculation of SAIDI and other reliability metrics, FY23 had a significantly larger number of days that did not contribute anything to the reported SAIDI values. The exclusion of major event days in FY23 due to Hurricane Fiona represents 9.8% of the total number of days a year. *Id.* Therefore, as the Expert Report states, when measuring reliability, it is inappropriate to compare FY24 with FY23 without considering the impact of Hurricane Fiona. *See* Expert Report, at p. 6.

Relevantly, the Expert assessed how reliability for FY23 can be fairly adjusted to reflect what it would likely have been had Hurricane Fiona not occurred. To carry out such an adjustment, the Expert considered that expected daily reliability would be different throughout the year based on typical weather patterns. Therefore, the FY23 adjustment uses a 30-day moving average approach that can account for this weather variation. The Expert also used historical data from FY22 through FY24 to create a mathematical model of expected daily reliability, which is explained in detail in the Expert Report, at pp. 6-7.

[12] Particularly, IEEE Standard 1366 was revised in 2003 to introduce a statistically based definition for classifying Major Event Days and to provide a methodology, the Beta Method, for determining Major Event Days. Once days are classified as normal or Major Event Days, appropriate analysis and reporting can be conducted. See illustratively IEEE Std 1366-2012, approved May 14, 2012, *see* Attachment 1 to Exhibit 1 at pp. 10-11.

The foregoing assessment shows that the expected additional SAIDI value that would have occurred during the Hurricane Fiona-related major event days had Fiona not occurred is 160 minutes, for a 13.1% increase. This means that all outage event values related to FY23 (including SAIDI) ought to be increased by 13.1% ("Fiona Adjustment") so that FY23 can be fairly compared to other fiscal years.

As reported to the Energy Bureau, the SAIDI values show an increase in SAIDI from FY23 to FY24 of 17.5%, but this is an improper comparison in terms of reliability performance due to the excluded major event days in FY23 because of Hurricane Fiona. The exclusion of major event days from reliability calculations allows a more accurate assessment of a utility's performance under "normal" circumstances and on "normal" days. Directly comparing FY23 to FY24 to measure reliability is not representative because for over a month in FY23, the T&D System did not experience "normal" days. *A fair comparison utilizing the Fiona Adjustment shows only a small increase of 3.8%, which should be within tolerance margins.*[13] *See* Expert Report, at p. 12. In fact, the Expert Report shows that the SAIDI values for the LUMA Years, taken together, show a slightly improving SAIDI trend.[14]

2. Comparing LUMA's reliability performance with PREPA's baseline of FY20 would be improper and unreasonable because of the increased frequency of non-excluded weather events during FY24, in contrast to FY20, a relatively mild year in terms of weather.

The February 11th Order also highlights that the reported SAIDI value for FY24 represents a deterioration over LUMA's FY20 baseline. However, the expert analysis shows that throughout

[13] According to the Expert Report, the SAIDI values resulting from the Fiona Adjustment are the following: SAIDI FY23 Adjusted: 1,378 versus SAIDI FY24: 1,431; for a change of +3.8%.

[14] "After adjusting for Fiona, FY24 shows a slight increase of 3.8% when compared to FY23 but a slight *decrease* of 7.1% when compared to FY22. These three years taken together show a slightly improving SAIDI trend." Expert Report, at p. 35.

FY24, Puerto Rico was recurrently impacted by severe weather (in the form of minor storms/grey sky days) that did not reach the threshold of a major event day and significantly impacted system reliability. In contrast, the data shows that FY20 was a relatively mild year in terms of weather.

The specific criteria that LUMA uses to identify a minor storm/grey sky day are as follows:

- NOAA National Weather Services ("NOAA") must have issued a severe weather warning for one or more locations in Puerto Rico; and
- The T&D System must have been severely impacted as determined by either (A) more than 150 outage events have occurred during the day; or (B) the maximum number of customers simultaneously interrupted during the day exceeds the sum of 20,500 plus the average daily maximum for the previous 30 days.

As explained by the Expert, while the contribution of minor storms/grey sky days to CMI (and therefore, SAIDI) in FY20 amounted to 27.0% (the lowest percentage out of all years examined), their contribution to CMI (and SAIDI) in FY24 was at 36.3% (the highest percentage), meaning that FY20 had relatively mild weather in terms of minor storms/grey sky days and FY24 had relatively severe weather in terms of minor storms/grey sky days. *See* Expert Report, at pp. 13-14.

As a result, to fairly compare FY24 reliability performance to the FY20 baseline, the Expert deemed it appropriate to reduce the percentage contribution of minor storm/grey sky days to CMI (and therefore SAIDI) in FY24 (*i.e.*, 36.6%) by 9.3%, so that its contribution is the same as the FY20 baseline (*i.e.*, 27%). The resulting SAIDI value is what would be expected if the weather severity in terms of minor storm/grey sky days was the same in FY24 as in FY20. *See* Expert Report, at p. 14.

As expounded by the Expert, the values reported to the Energy Bureau show an increase in SAIDI from FY20 to FY24 of 18.4%. However, this is an improper comparison in terms of reliability performance due to FY20 being a mild weather year and FY24 being a severe weather year. Therefore, comparing FY20 and FY24 without adjusting the numbers to account for the impact of non-excluded weather events would, in part, be penalizing LUMA based on bad weather. Expert Report, at pp. 14-15.

Weather severity aside, comparing LUMA's FY24 performance to FY20 is also misleading because, as will be discussed in the next section, PREPA's collection and classification of outage data was dubious, and its failure to record outage events made PREPA's reported SAIDI artificially low.

3. Comparing LUMA's reliability performance with PREPA's baseline of FY20 is improper and unreasonable because after taking over the operation of the T&D System, LUMA has strengthened its data collection process and is capturing more complete outage data as compared to PREPA.

According to the Expert, since LUMA is collecting complete outage information, SAIDI and CMI experienced in the PREPA Years cannot be fairly compared to SAIDI and CMI experienced during the LUMA Years. More complete outage information results in a higher reported SAIDI than would otherwise be reported if data collection had not improved. The Expert opines that because the total number of outages in the PREPA Years was essentially holding constant, the large increase seen in the LUMA Years cannot be attributed to actual outages increasing by this amount. Rather, the large increase seen in the LUMA Years compared to the PREPA years "is likely due, at least in a substantial amount, to different data collection practices".[15] *See* Expert Report, at p. 17.

---

[15] Exponent uses the term "Step Change" when referring to the increase in outages due to data collection practice changes from PREPA to LUMA.

As an indication of the above, the Expert points out that during the PREPA Years, recorded equipment-related outages remained stable at between about 10,500 and 11,000, showing only a slightly downward trend, even though PREPA had dramatically reduced equipment maintenance for many years prior. However, from FY21 to FY22, the reported equipment outages suddenly increased from 10,489 to 14,627 (39.5%), making it reasonable to conclude that, upon taking over the operation of the T&D System, LUMA commenced to capture a much higher percentage of equipment outages than PREPA and began to classify them as such properly.[16] To illustrate this, the Expert Report calls attention to equipment failures that occur on the secondary distribution system (*i.e.*, the final stage of electricity delivery), which dramatically increased from 2,286 in FY21 to 5,210 in FY22, tending to show that PREPA underreported secondary distribution system equipment related outages in its outage management system. *See* Expert Report, at pp. 18-19.

The Expert also notes that in addition to the SAIDI increase caused by LUMA's improved outage data collection practices, operational changes established by LUMA to increase and improve safety during outage response and restoration could also have contributed to increased SAIDI values (likely in about 12.5%).[17] *See* Expert Report, at pp. 16-17.

---

[16] The rigor with which LUMA is collecting and classifying outage data is evidenced by the decrease in outage events with "Unknown" cause, going from 6,113 with PREPA in FY19 to 2,912 with LUMA in FY24. *See* Table: Outage Events by Cause, at p. 13 of Expert Report.

[17] Specific components of these safety enhancements include the following;

Equipotential Bonding and Grounding. developed a new and extensive work method with an expectation that time is taken to properly and effectively ground a work area before commencing work.

Pre-work Hazard Assessments. Expectation that a thorough hazard assessment and corresponding hazard mitigation activities are undertaken before any work is started.

Job Site Tailgate Meetings. Tailgate meeting are to review hazards/mitigations, work plan and ensure alignment of all workers on the worksite. Also it is expected that the time is taken whenever work scope changes to have thorough tailgate safety meeting and all workers sign-off on what was discussed.

Standdowns. When significant safety events happen or a pattern of smaller events occur, that the following morning crews are stood down from starting work to review the immediate findings from the safety events.

3-way communication/PSWS. A new phone system has been implemented which records calls into the operating centers. The expectation is that the time is taken to properly complete 3-way communication protocol and understanding of switching order before commencement of switching.

Because safety is paramount during outage restoration, and careful planning and execution to prevent accidents should be a top priority, LUMA respectfully submits that it should not be penalized to the extent that establishing the above actions increased SAIDI. Moreover, based on the Expert's calculations, assuming PREPA had LUMA's current safety measures in place during FY20, its SAIDI value would have increased by about 5.3%.[18]

B. Exponent's Assessment of LUMA's Reliability Performance from FY22 through FY24

Exponent analyzed LUMA's outage data for FY22 through FY24, which is summarized in the table at p. 23 of the Expert Report. Upon review of LUMA's outage data, the Expert made the following observations.

First, CMI in the "Unknown" category decreases drastically from FY22 to FY 24 (from 621.2 to 108.5M). Events in the "Unknown" category also dropped drastically from FY22 to FY24 (from 6,367 to 2,912). Based on the information provided by LUMA, upon commencing operations in June 2021, LUMA established the practice of requiring line patrols to identify likely outage causes. In early 2024, additional efforts were undertaken to minimize the number of "Unknown" causes. According to Exponent, the reduction in CMI and Events under the "Unknown" category from FY22 to FY24 shows that LUMA emphasizes identifying outage causes. Efforts to reduce the "Unknown" causes also slow down response time, as field employees spend more time and effort attempting to determine the outage cause. *See* Expert Report, at pp. 23-24.

Second, the most commonly identified outage caused by LUMA's line patrols is vegetation. Therefore, much of the increases seen in vegetation outages are due to reductions in

[18] This is without considering the impact of minor storms/grey sky days in FY24 *vis á vis* FY20 and ignoring the fact that it is improper to directly compare FY24 to FY20 in view of the disparities between LUMA and PREPA's data collection processes.

the "Unknown" category (from 6,367 in FY22 to 2,912 in FY24) and LUMA's best efforts to properly classify events that would have otherwise been recorded as "Unknown" as vegetation related outage events. Notwithstanding, since the increase in the vegetation category is larger than the reduction in the "Unknown" category, Exponent acknowledges there is an actual increase in vegetation-related outages.[19] *Id.*

Third, there is an overall increase in outage events from FY22 (38,444) to FY24 (46,222). With all the reductions in the "Unknown" category being allocated to vegetation, the Expert assumes that increases in the remaining Events categories are assumed to be actual increases. As for these remaining Event categories, Exponent notes that Combined Lightning/Weather Events rose from FY22 to FY24 from 4,813 (383+4,430) to 6,479 (2,871+3,608), representing an increase of 1666 events,[20] which is compatible with the increase of non-excluded weather events impacting the T&D System in FY24, as discussed in Section III (A) (2). The Expert also notes a large increase in the "Public" category, over which LUMA has little control[21] , and in the "Other" Category.[22] *See* Expert Report, at pp. 24-25.

Upon reviewing and analyzing LUMA's outage data, the Expert concluded that even though LUMA was faced with a large increase in the number of outage events from FY22 to FY24 —a large percentage out of LUMA's control — the impact to CMI increase was proportionally small. Specifically, whereas overall outage events increased by 20.3% from FY2022 to FY 2024

---

[19] This coincides with LUMA's response to the Energy Bureau's RFI of August 9th, 2024.
[20] According to Exponent, the categories of "Lightning" and "Weather" must be considered together, as it is clear that earlier years tended to classify a lightning-caused outage as weather.
[21] These include public-cause events such as car-pole hits and dig-ins, and other intrusions.
[22] The Other category includes the following cause codes: Failed Protection; Feeder Load Transferred; Human Error; Other Causes; Raise / Lower Service Transformer Tap; Removal of Oil Container or Asbestos and Trip Due To Overload. As explained in the Expert Report, the increase in the "Other" category is almost entirely due to the "Feeder Load Transferred" cause code. This cause code is used when connected feeders are impacted by the same event and the CMI.

(from 38,444 to 46,266), CMI actually *decreased* by 7.1% (from 2,300 million to 2,137 million). The Expert concludes that this decrease in CMI has been accomplished primarily by reducing the number of customers impacted by certain outages, largely through LUMA's distribution automation (DA) and regional reliability initiatives. Such initiatives and their impact on CMI are discussed in detail at p. 26 of the Expert Report.[23]

1. The impact of weather severity during FY24 *vis à vis* FY23.

Because the February 11th Order suggests that LUMA's alleged noncompliance stems from the increase in the SAIDI reported from FY23 to FY24, Exponent also assessed weather severity for these two time periods to identify how this outside stressor should be factored in when comparing the variance in reliability between these two years.[24] For this purpose, the Expert analyzed weather information from the NOAA Monthly and Annual Reports. *See* Expert Report, at p. 28. Upon said analysis, the Expert observed that (i) except for Hurricane Fiona in September 2022, the monthly rainfall averages were much higher in FY24 than FY23; and (ii) the monthly temperature averages were also much higher in FY24 than FY23.

As stated by the Expert, these types of weather patterns will have two primary impacts on reliability. First, increased temperatures and rainfall will cause vegetation to grow faster. Second, increased temperatures will increase system loading, causing equipment to increase in temperature due to this loading but less able to dissipate this head due to higher ambient temperatures. Therefore, the weather patterns seen in FY23 and FY24 resulted in higher numbers of outages due

[23] To buttress the previous point, the Expert Report also underscores that the number of substation outage events has been essentially steady, even as substation equipment continues to age. Similarly, transmission outage events have been holding steady during the LUMA Years, which showed a reduction when compared to the PREPA Years.
[24] This analysis is separate from the impact of excluded major event day due to Hurricane Fiona (discussed in Section III (A) (1) above, and focuses on actual experienced weather conditions.

to vegetation growth and equipment overloading, showing that changing weather tends to worsen reliability in a manner that is outside LUMA's control. *See* Expert Report, at pp. 24-27.

2. LUMA's Approach to Equipment Reliability and Vegetation Management.

As advanced to the Energy Bureau in LUMA's responses to the regulator's RFI of August 9th, 2024, equipment failures and vegetation issues were the main drivers of the SAIDI increase in FY24.[25] Considering that, the Expert also assessed the overall condition of the electric grid prior to LUMA commencing to operate and maintain the T&D System and the actions that LUMA has taken to improve the performance of the T&D System from an equipment reliability perspective. The Expert's key observations on the conditions of the T&D System confirm LUMA's position that, while operational, the T&D System requires significant maintenance and potential replacement, and that it remains fragile from years of lack of maintenance and inspections and damage from external events. *See* Expert Report, at pp. 28-30.

Nonetheless, the Expert notes that LUMA has engaged in major activities to maintain and improve equipment reliability, including: the establishment of asset management processes to ensure that equipment condition is known and that data management systems are in place to manage the assets; inspection and maintenance processes to ensure that equipment and materials are kept in good operating condition; and development of capital projects to ensure that equipment and materials are replaced at appropriate intervals based on condition and system needs.[26]

From the Expert's perspective, LUMA has prioritized the transmission system issues for capital improvement to prevent major events, but much of the work applies to reductions in overall system reliability. *See* Expert Report, at p. 32. The Expert also evaluated LUMA's current vegetation management strategy, which includes the following two activities: (i) a one-time

---

[25] *See also* summary of LUMA's outage data at Section 7 of the Expert Report.
[26] These vegetation management strategies are described in more detail at pp. 33-34 of the Expert Report.

vegetation clearing program that is planned to be completed between FY25 and FY28[27]; and (ii) an ongoing operations vegetation management, which includes continuing patrols and clearing, focused on areas showing outages[28] From the Expert's perspective, all the vegetation work will positively impact reliability by assisting in reducing the number of vegetation-related outages. *See* Expert Report, at p. 34.

Based on the foregoing discussion, the Expert concludes that LUMA should not be fined for its FY24 SAIDI performance, as it compares favorably to both the SAIDI performance for FY23 and the baseline year of FY20 when relevant factors affecting reliability are properly considered so that fair comparisons are made. Although the reported FY24 SAIDI value is higher than the SAIDI values reported for FY23 and FY20, the reported FY23 SAIDI value is not directly comparable to the FY24 value because of Hurricane Fiona, and is also not comparable to the FY20 baseline due to differences in LUMA's operation and outage approach (including an improved data management process and implementation of safety measures), as compared to PREPA. Furthermore, during the LUMA Years, SAIDI has shown a slight trend of improvement. Expert Report, at pp. 35-36.

Finally, Exponent also assessed the appropriateness of LUMA's current corrective action plan as delineated in LUMA's Response and determined that it is appropriate for effectively managing SAIDI, and, if fully implemented, should eventually result in a downward SAIDI trend.

In sum, the detailed analysis in the Expert Report demonstrates that the facts or applicable regulations do not support the alleged noncompliance. The Expert Report shows that the reported SAIDI value for FY24 does not represent a decrease in system reliability, and any claim to the

[27] The scope of this effort covers all six regions on the Island and incorporates clearing across all substations, transmission lines, distribution lines and telecom facilities. The first project in San Juan was started in 2024.
[28] These initiatives are described in more detail at pp. 33-34 of the Expert Report.

contrary simply lacks factual and legal support. As such, the notice of noncompliance and proposed fine are clearly unwarranted and must be vacated.

C. The February 11th Order is legally flawed because it contravenes the Energy Bureau's Regulations and violates LUMA's right to due process of law.

1. The Energy Bureau has consistently characterized performance benchmarks as illustrative.

This Energy Bureau initiated Case No. 0007 to set performance baselines and compliance benchmarks for Puerto Rico's electric system. Those performance baselines and benchmarks would be used to develop the corresponding targets for certified electric service companies such as LUMA. *See* Resolutions and Orders of May 14, 2019, and December 23, 2020. Consequently, LUMA submitted filings that addressed the Energy Bureau's data on PREPA's baselines and presented proposed performance baselines, metrics, and an initial assessment of compliance benchmarks. *See Motion Resubmitting LUMA's Comment on Performance Baselines and Metrics Based on Data Presented on January 19th, 2021, By the Energy Bureau, and Resubmitting Proposed Performance Metrics and Baselines* dated February 5, 2021; *Motion Submitting Luma's Reply to Comments Filed by PREPA and Stakeholders on Performance Baselines, Performance Metrics and Compliance Benchmarks* dated February 19, 2021; *Motion Submitting LUMA'S Sur Reply and Comments on the Information Presented at the Technical Conference of February 22, 2021,* dated March 1, 2021.

On April 8, 2021, this Energy Bureau issued a Resolution and Order ("April 8th Order") with its determination on PREPA's performance baselines, addressing LUMA's submissions as well as those filed by stakeholders. It included a series of orders: (1) establishing PREPA's performance baseline and (2) setting the prospective metrics to be reported by PREPA. The baselines took into consideration PREPA's performance for FY20. Regarding the reliability metrics (including SAIDI), the Energy Bureau recognized the importance of high-quality data and PREPA's obligation to provide data based on calculations consistent with IEEE 1366 methodology. The Energy Bureau instructed that the baselines and benchmarks would be, among other things, the basis to establish the performance incentives or targets to apply to LUMA in Case No. NEPR-AP-2020-0025. *See* April 8th Order, at pp. 4-5.

Subsequently, in the May 21st Order, the Energy Bureau approved and established the baselines and benchmarks for the metrics, and, upon commencing operations under the T&D OMA, LUMA began to submit quarterly reports to the Energy Bureau, providing ongoing updates of performance metrics for the T&D System, including SAIDI values.

LUMA acknowledges that the baselines and benchmarks established by the Energy Bureau in Case No. 0007 are not inconsequential. However, filing quarterly reports in Case No. 0007 has always been an evolving information-gathering process, allowing for future revisions to the existing performance metrics. *See* Resolution and Order of May 21st, 2021, at p. 15 ("the establishment of performance compliance metrics and benchmark shall be an ongoing process"). Never did this Energy Bureau warn LUMA that liability could attach as a result of the metrics reported in Case 0007. As discussed below, the Energy Bureau's existing regulations are silent at worst, and ambiguous at best, when addressing the parameters to be followed by this Energy Bureau to assess compliance with the established performance metrics, and the framework for imposing penalties accordingly.

2. The Energy Bureau failed to follow its own regulations when issuing the Notice of Noncompliance.

The February 11th Order initiated the instant proceeding in accordance with Section 14.01 of the *Regulation on Adjudicative, Notice of Noncompliance, Rate Review, and Investigation Proceedings*, Regulation Number 8543 of December 18, 2024 ("Regulation 8543"), which provides that the Energy Bureau may issue a Notice of Noncompliance if it learns that a person has incurred, is or may be incurring in a violation of Puerto Rico's public energy policy, Act 57-2014, any regulation of the Energy Bureau, or any other law whose interpretation, implementation, or enforcement falls under the jurisdiction of the Energy Bureau. However, the reported SAIDI value for FY24 does not violate any of the aforementioned. Thus, Section 14.01 of Regulation 8543 is not applicable here.

Relevantly, Section 15 of Regulation 8543 provides the Energy Bureau with an investigation mechanism to identify if a party is violating or breaching an energy public policy under the jurisdiction of the Energy Bureau. Section 15 of Regulation 8543 allows the Energy Bureau to investigate any matter related to the electric power industry, as well as any matter within its jurisdiction. It establishes that once the investigation reveals a violation or breach of the public energy policy of Puerto Rico, then the Energy Bureau may issue a Notice of Noncompliance to the party. Thus, if the investigation concludes that a violation or breach has been committed, the Energy Bureau may issue a Notice of Noncompliance to the party and start proceedings against them, where penalties may be imposed. The Energy Bureau, however, did not initiate an investigation to comprehend more fully the circumstances surrounding the reported SAIDI value for FY24, evaluate LUMA's explanations, and objectively determine what corrective actions, if any, should be asked from LUMA to remediate the situation, before even considering whether a Notice of Noncompliance was appropriate. That failure to use a mechanism available under Regulation 8543, led the Energy Bureau to include findings in a Notice of Noncompliance that unreasonably do not consider all the relevant information and explanations regarding the reported SAIDI values, which explanations LUMA has outlined in this Motion and the accompanying Expert Report and LUMA's Response. *See* **Exhibits 1** and **2**.

LUMA acknowledges that upon receipt and evaluation of LUMA's System Data for April through June 2024 the Energy Bureau notified an RFI to LUMA requesting certain explanations on the reported SAIDI values for FY24. However, under no circumstances can said course of action be considered an investigation under Section 15 of Regulation 8543. For one, the Energy Bureau notified the RFI as part of the proceedings in Case No. 0007, which, as discussed above, is an information-gathering docket; for two, the Energy Bureau did not warn LUMA that it intended to investigate (or had commenced to investigate) LUMA's reliability performance in view of the reported FY24 SAIDI value. For three, neither did the Energy Bureau issue a report after concluding the investigation nor inform LUMA of its right to answer or object to the same, as required by Sections 15.07 and 15.08 of Regulation 8543.[29] Relevantly, pursuant to Section 15.09 of Regulation 8543, it is only after an investigation reveals a violation or breach of the public energy policy of Puerto Rico, or any rule or regulation under the jurisdiction of the Energy Bureau, that the Energy Bureau may, at its discretion, issue a Notice of Noncompliance. Here, the Energy Bureau did not adhere to its own process before issuing the Notice of Noncompliance and, for that reason, the notice is legally flawed. *See Fuentes Bonilla v. E.L.A.*, 200 DPR 364 (2018) (*noting* that the case presented an anomalous scenario because the agency did not obey its own regulations); *Ayala Hernandez v. Consejo de Titulares*, 190 DPR 547, 568 (2014) (*holding* that when an administrative agency issues a regulation, it has the responsibility of adhering to the same rigorously); *Lopez Leyro v. E.L.A.*, 173 DPR 15 (2008) (*ruling* that administrative agencies cannot ignore their own rules and regulations and that an agency's interpretation of its own regulations must be based on sound reason, in accordance with the applicable enabling law); *see also Maldonado v. Dpto. De Correccion*, KLRA20110089, (Puerto Rico Court of Appeals, December

---

[29] As a matter of fact, there is no such report. The "performance analysis" alluded to by the Energy Bureau in the February 11th Order does not exist.

23, 2011) 2011 PR App. LEXIS 3183 (remanding the case to the administrative agency for it to fully comply with its own regulations).

As the February 11th Order's holdings regarding the reported SAIDI values for FY24 do not support a finding of non-compliance with the energy public policy or applicable laws or regulations, it does not adhere to Section 14. It cannot be considered a proper Notice of Noncompliance under Regulation 8543. Furthermore, the Energy Bureau failed to support its findings *via* an ongoing investigation proceeding per Section 15 of Regulation 8543. Given these circumstances, LUMA respectfully requests that this Energy Bureau vacate the February 11th Order as being issued in contravention to Regulation 8543.

3. The Energy Bureau violated LUMA's Due Process Rights by prejudging LUMA's compliance with the SAIDI metric without affording LUMA a meaningful opportunity to be heard

The constitutional guarantee of due process assures everyone that they shall not be deprived of liberty or property without a fair, equitable, and reasonable trial. *See* Const. E.L.A. art. II, sec. 7, 1 LPRA; Const. USA Amdt. XIV §1; Const. USA, Amdt. V; *see e.g., Rivera Rodriguez & Co. v. Lee Stowell*, 133 DPR 881, 887 (1993); *López Vives v. Police of PR*, 118 DPR 219, 231 (1987). In its substantive aspect, the guarantee of due process of law requires evaluating the constitutionality of a state action to protect fundamental rights. *Rivera Santiago v. Srio. Treasury*, 119 DPR 265, 273 (1987). Under this guarantee, the state is prevented from affecting the property or freedom interests of an individual in an unreasonable, arbitrary, or capricious manner. *Hernández v. Secretario*, 164 DPR 390, 394-95 (2005) (citing cases); *see also, e.g., Meléndez de León v. Keleher*, 200 DPR 740, 759 (2018) ("due process of law 'represents a barrier to arbitrary or capricious state actions affecting citizens' fundamental rights.").

Substantive protection extends to arbitrary and capricious government actions by administrative agencies. *See, e.g.*, ("due process of law also provides protection against administrative arbitrariness"); *Pearson v. City of Grand Blanc*, 961 F.2d 1211, 1217 (6^{th} Cir. 1992) ("The right not to be subject to 'arbitrary or capricious' action by a state either by legislative or administrative action is commonly referred to as a "substantive due process right."). Procedural due process, on the other hand, deals with "the minimum procedural guarantees that the State must provide to an individual when affecting his life, property or liberty." *Rivera Santiago*, 119 DPR at 273. "The essential guarantee of the due process clause is that it is fair. The procedure must be fundamentally fair to the individual in resolving the facts and rights that serve as the basis for those governmental actions that deprive him of his life, liberty, or property." *Id.*, at 274 (citations and internal quotation marks omitted).

In evaluating claims of due process violations, courts first determine whether a proprietary or libertarian interest is at stake. *Rivera Rodriguez & Co.*, 133 DPR at 887. Once it is determined that this requirement has been met, due process is defined given that "different situations may require different types of proceedings, but there always remains the general requirement that the governmental process must be fair and impartial." *Id.* at 888. Due process is circumstantial and pragmatic in nature, so its requirements will depend on the context of the procedure. *Punta de Arenas Concrete v. Auction Board, Mun. Anthills*, 153 DPR 733, 740-42 (2001).

Among the guarantees that make up due process, jurisprudence has recognized that the administrative decision must be informed, with knowledge and understanding of the evidence corresponding to the case. *A.D.C.V. v. Superior Court*, 101 DPR 875, 883 (1974); *see also Rafael Rosario Assoc. v. Dept. Familia*, 157 DPR 306, 330 (2002). In addition, the findings of fact and the reasons for the administrative decision must be stated. *Rivera Santiago*, 119 DPR at 274. To ensure due process guarantees, parties must have an opportunity to present and refute evidence and be able to do so effectively. *See Rentas Nieves v. Betancourt Figueroa*, 201 DPR 416, 429 (2018). Those parties to an administrative procedure have the right to participate effectively. *Commission of Citizens to the Rescue of Caimito v. G.P. Real Property S.E.*, 173 DPR 998, 1014 (2008) (by the imperative of due process, parties must be notified of administrative determinations so that they can effectively participate and challenge determinations in court). In view of this, "[t]he right to a public hearing would be meaningless if [the administrative body] were allowed to base its decision on evidence received without the knowledge of the parties, outside the hearing, without allowing the interested parties to rebut or explain it by cross-examining or presenting other evidence to the contrary." After all, due process guarantees are constitutional imperatives.

Due process guarantees also include giving individuals adequate notice of actions the state prohibits or requires. *See White Tel. Co. V. Fed. Commc'ns Comm'n*, 991 F.3d 1097, 1116 (10th Cir 2021) (citation omitted). This pursues two guiding purposes: (1) that the regulated entity can conform its conduct to the requirements of the state; and (2) to prevent agencies from acting unreasonably or arbitrarily. *See FCC v. Fox Television Stations, Inc.*, 567 U.S. 239, 253, (2012); *see also Henríquez v. Consejo Educación Superior*, 120 DPR 194, 202 (1987).

In the instant case, even though Section 15 of Regulation 8543 afforded the Energy Bureau a mechanism to conduct an exhaustive investigation into LUMA's reported SAIDI performance, upon receipt of LUMA's System Data and responses to RFI in Case No. 0007, the Energy Bureau chose to forego that course of action and decided to pass judgment on the subject matter through an unknown and cryptic process, foreclosing LUMA's rights to be timely and properly informed of the Energy Bureau's concerns. The Energy Bureau carried out what it labeled as a "performance analysis" whose criteria and parameters are unknown to LUMA --even after having reviewed the administrative record. According to the February 11th Order, said "analysis" led the Energy Bureau to conclude *inter alia* that a Notice of Noncompliance is warranted because there is a severe worsening of reliability and a negative trend in outage duration. However, the administrative record in both Case No. 0007 and the instant case does not have a single document either on the alleged "performance analysis" performed by the Energy Bureau or otherwise showing the rationale underpinning the Energy Bureau's decision.[30]

This lack of transparency and fairness not only renders the Energy Bureau's decision arbitrary but also violates fundamental due process principles by depriving LUMA of a clear understanding of the rationale behind the Energy Bureau's concerns (and eventual determination) with the reported FY24 SAIDI value and of a timely chance to present its side of the story and defeat any potential adverse findings.

The Energy Bureau might argue that it is giving LUMA sufficient notice and opportunity to be heard in an unbiased process now, through the February 11th Order, hut the record clearly shows otherwise. A reading of the February 11th Order reveals that the Energy Bureau appears to have predetermined its conclusion regarding the controversy. In fact, the document is replete with findings of fact and conclusions of law, such as the following:

- LUMA is required to comply with performance standards, including SAIDI;
- Based on reports submitted to the Energy Bureau and the performance analysis conducted by [the Energy Bureau], a failure to considerably improve reliability and meet the established SAIDI benchmark has been identified;
- The SAIDI metric for Fiscal Year 2024 ("FY24") is worse than FY23,[6,] indicating an increase in the average duration of service interruptions and/or reflecting longer service outages;

[30] Relevantly, upon review of the administrative record, LUMA can confirm that Case No. 0007 reveals a complete absence of any documents that explain the Energy Bureau's rationale for its decision or even an analysis of the System Data containing the reported FY24 SAIDI value. Meanwhile, when LUMA contacted the Energy Bureau on March 6, 2025 to obtain access to the administrative record, the Energy Bureau confirmed that the record for the instant proceeding then consisted of the February 11th Order.

- Following a review of LUMA's FY24 performance report, SAIDI results for this period were worse than those reported for the previous year, indicating a decline in service reliability;
- LUMA's SAIDI has surpassed **both the previous year and the regulatory threshold**.
- This noncompliance represents a failure to meet the reliability standards established to ensure an electric system that is resilient and responsive to consumer needs, in alignment with the principles set forth in Act 57-2014 and Act 17-2019[31];
- Given the severity of the situation, a fine is necessary to counteract this negative trend in outage duration and ensure compliance with performance standards.
- Upon evaluation of the severity of noncompliance with SAIDI, considering factors such as the extent of deviation from established standards, the duration of noncompliance, and the impact on consumers, the Energy Bureau is inclined to impose LUMA, a fine of **$1.825 million**.

Far from reflecting the initiation of a process to assess LUMA's SAIDI performance impartially, the above-cited language in the February 11th Order indicates that the Energy Bureau essentially decided the outcome of this matter in advance and is now affording LUMA an opportunity to be heard -after the fact- only in a "pro forma" manner.[32]

As previously discussed in the preceding section, according to Section 15 of Regulation 8543, the Energy Bureau has the authority to investigate *any matter* related to the electric power industry or within its jurisdiction, and, upon conclusion of the investigation, may issue a notice of noncompliance, if warranted. Notably, as part of the investigative process, the target person has an obligation to cooperate and, upon issuance of the investigation report, may submit, in writing, objections, arguments, or comments to the same. It is only after the investigation ends that, depending on the conclusions, the Energy Bureau may file a Notice of Noncompliance and assess whether the imposition of a fine is appropriate. None of that happened here. The Energy Bureau simply chose to "put the cart before the horse" in a manner that clearly prejudiced LUMA.

[31] Known as the *Puerto Rico Energy Public Act*, Act 17-2019 ("Act 17-2019")

[32] The language in the Notice of Noncompliance is more akin to a Show Cause Order where the Energy Bureau is instructing to appear and explain why the proposed action (i.e. finding of a violation and imposition of a fine) should not be taken against LUMA. Besides unfair, such course of action runs afoul of the process established by Sections 14 and 15 of Regulation 8543.

Behind closed doors, the Energy Bureau prejudged LUMA's SAIDI performance; ruled that a notice of noncompliance was appropriate; reached a decision to impose a fine on LUMA likely; and preliminarily set the amount of the fine- in a significant amount, all without formally investigating the subject matter and without affording LUMA a genuine opportunity to be heard and present its side of the story. In doing so, the Energy Bureau bypassed the essential procedural safeguards and violated the most elementary and fundamental due process principles. *See Mathews v. Elridge*, 42 U.S. 319, 333 (1976) (ruling that the fundamental requirement of due process is the opportunity to be heard at a meaningful time and in a meaningful manner).

D. A fine pursuant to the February 11th Order Has no basis in applicable law, regulation, and case law, thereby contravening applicable due process guarantees.

In our jurisdiction, given the existing due process guarantees, decisions by administrative agencies imposing fines shall not exceed statutory authorization, must be supported by substantial evidence in the administrative record, and cannot amount to a clear abuse of discretion. *See Comisionado de Seguros v, Antilles Ins. Co.*, 145 DPR 226, 233-34 (1998); *Assoc. Ins. Agencies, Inc. v. Com. Seg. PR*, 144 DPR 425, 439-41 (1997); *see also e.g., ECP Incorporated v. Oficina del Comisionado de Seguros*, 205 DPR 268, 281 (2020) (*stating* the general rule that decisions by administrative agencies should be reasonable and based on the administrative record).

The determination to impose fines entails the exercise of discretion and a concomitant avoidance of arbitrary actions. In the context of administrative law, the Puerto Rico Supreme Court has held that the exercise of discretion by an administrative agency must be rooted in reasonableness and accordance with applicable law. *See e.g., Ramírez v. Policía de PR*, 158 DPR 320, 339 (2002). Discretion, in turn, has been defined as a form of reasonableness applied to judicial discernment to reach a just conclusion. *See, e.g., Banco Popular de PR v. Mun. de Aguadilla*, 144 DPR 651, 657-58 (1997); *Pueblo v. Ortega Santiago*, 125 DPR 203, 211 (1990).

Section 6.36 of Act 57-2014, as amended by Act 17-2019, gives the Energy Bureau the authority to "impose administrative fines for violations of the Act, or the regulations and orders issued thereunder, committed by any person or electric power company subject to its jurisdiction, of up to a maximum of twenty-five thousand dollars ($25,000) per day." 22 LPRA §154jj (2024) (translation ours). Meanwhile, Article XII of Regulation No. 8543, also known as *Regulation on Adjudicative, Notice of Noncompliance, Rate Review and Investigation Proceeding* ("Regulation 8543"), establishes that the Energy Bureau "may issue any order or resolution it deems necessary to give effect to the purpose of Act. No. 57-2014 [and] to compel compliance with any law whose interpretation and implementation is subject to the jurisdiction of the [Energy Bureau] and to enforce its rules, regulations, orders, and decisions." Regulation 8543, Section 12.01.

Here, even assuming for the sake of argument that LUMA did violate either Puerto Rico's public energy policy or a law or regulation under the jurisdiction of the Energy Bureau, which LUMA denies, the February 11th Order neither identifies the alleged violation nor the Energy Bureau's rationale behind the conclusion that there is a severe worsening of reliability. In fact, it is unclear to LUMA if the alleged violation stems from the SAIDI increase in and of itself, if it is because the reported value is greater than the reported value for FY23, or because the Energy Bureau believes there is a negative and irreversible trend in outage duration. In any event, not having afforded LUMA the opportunity to be heard before the Energy Bureau concluded that a "violation" occurred and before deciding that a fine is necessary contravenes due process principles. *Compare with Puerto Rico Tel. Co. v. Telecommunications Regulatory Bd.*, 189 F.3d 1, 18 (1 st Cir. 1999) (finding that PRTC was given due process where undisputed facts show that the Board held two days of trial-type hearings during which PRTC had the opportunity to present evidence and to challenge CCPR's evidence before a neutral decisionmaker, and that the Board ultimately rendered its ruling and gave supporting reasons in a written decision) and *Vélez Amador v. United States Coast Guard*, No. 20-1724, 2023 U.S. Dist. LEXIS 55147 (D.P.R. March 28, 2023) (in the context of a petition to review a decision made by the United States Coast Guard in connection with a Notice of Violation issued pursuant to 46 U.S.C. §2302 (a), *dismissing* movant's due process claim because the agency informed movant that a final decision would be made *after* movant had the opportunity to respond; that he could submit evidence in lieu of a hearing or request a hearing in writing, and that failure to request a hearing within 30-days would result in a waiver of his right to the same).

As previously discussed, the proposed fine in the February 11th Order is unjustified because the administrative record is devoid of factual findings --substantiated by a proper analysis of the FY24 SAIDI value and of LUMA's overall reliability performance-- to sustain the Energy Bureau's conclusion that LUMA violated either Puerto Rico's public energy policy or a law or regulation under this agency's jurisdiction. As a matter of fact, the Expert's analysis shows that the Energy Bureau's conclusion of worsening in reliability for FY24 is unfounded.

Meanwhile, it is clear that the applicable law, regulations, and jurisprudence establish that the Energy Bureau can only impose fines under specific parameters. As stated in the preceding Section, the Energy Bureau has not opened an investigation on the SAIDI metric for the T&D System and LUMA's performance thereunder. Thus, imposing a fine on LUMA without complying with Section 14 and Section 15 of Regulation 8543 violates LUMA's due process rights.

1. The Energy Bureau Has Not Established a Mechanism for Penalties for Non-Compliance Under Regulation 9137.

The Energy Bureau has established regulations recognizing the Bureau's right to conduct a process for establishing performance incentive mechanisms and penalties. The *Regulation for*

Performance Incentive Mechanisms, Regulation No. 9137 of December 13, 2019 ("Regulation 9137") provides in its Section 7 that the Energy Bureau shall establish the Bureau's policy for their Performance Incentive Mechanisms, which shall include: economic incentives and investment payback, customer services, compliance with standards established in Act 17-2019, compliance with federal and local environmental policies, and others. *See* Regulation 9137, Section 7.1. These Performance Incentive Mechanisms shall be clearly defined, easily interpreted, and verified. *Id.*

Relevant to the instant proceeding, Regulation 9137 provides tbat, upon the establishment of metrics, targets, and financial incentives through an initial proceeding, the Energy Bureau shall hold an annual proceeding to evaluate the performance report of an electric power service company, to make any adjustments to the performance incentive mechanisms, and to determine whether to establish, eliminate, or modify any metric, target, or financial incentive.[33] *See* Regulation 9137, Section 3.1. Section 3.3 (E) of Regulation 9137 adds that, at the conclusion of each annual proceeding, the Energy Bureau shall issue a Final Order, based on conclusions of law and findings of fact, which shall document its rulings on the final annual report's compliance during the reporting period and incorporate findings from any audit, if ordered and available during the reporting period. It further adds that, if applicable, the Energy Bureau shall also set forth a new set of metrics and targets, and any financial incentives to be established, for the next reporting period. Also, in connection with the evaluation of the annual performance report filed by the electric power company, Section 3.7 of Regulation 9137 provides that, once the annual proceeding is commenced, the Energy Bureau, at its discretion, may issue an Order scheduling a Technical

[33] Regulation 9137 defines "metric" as "a quantifiable indicator which can be used and tracked over time to evaluate an entity's performance". It defines target" as "the goal that may be associated with a metric against which, if it is so associated, a [power service] Company's performance shall be evaluated."

Conference for the company to present its most recent annual performance report, and answer questions from the Energy Bureau.

Significantly, even though Section 7.2 of Regulation 9137 also provides the Energy Bureau with the means to establish mechanisms to impose penalties for noncompliance with a metric under its authority pursuant to Section 6.36 of Act 57-2014, the criteria and parameters for the imposition of such penalties have not been defined by this Energy Bureau yet.

The touchstone of due process is the protection of the individual against arbitrary action without clear parameters. Here, even though Regulation 9137 allows for the imposition of penalties for the non-compliance of a metric, LUMA's due process has yet again been infringed as the February 11th Order alludes to the Energy Bureau's inclination to impose a fine even though the Energy Bureau has not established clear guidelines for noncompliance with the reliability metrics. *See*, *Asoc. De Farmacias v. Dpto. De Salud*, 156 D.P.R. (2002) (*stating* that based on due process considerations, agencies must issue regulations to avoid arbitrary actions when ruling on individual rights). LUMA respectfully submits that the absence of defined standards to measure a company's compliance and criteria to assess the amount of the penalty imposed paves the way to arbitrary and unreasonable action. Moreover, when, as previously mentioned, the Notice of Noncompliance herein was issued outside the confines of Sections 14 and 15 of Regulation 8543 and absent the annual proceeding to evaluate a company's performance report delineated by Regulation 9137. In sum, the imposition of penalties for the alleged worsening of system reliability based on the reported SAIDI metrics is not procedurally appropriate or correct in this case, and, for that, the February 11th Order should be vacated.[34]

[34] It should be noted that this Energy Bureau precisely determined not to include a penalty mechanism as part of its evaluation of LUMA's proposed incentive metrics in Case No. NEPR-AP-2020-0025. *See* Final Resolution and Order dated January 26, 2024, and Resolution and Order dated June 14, 2024.

2. Alternatively, the Energy Bureau has no basis to impose a fine based on cumulative daily violations.

The Energy Bureau stated in the Notice that "[u]pon evaluation of the severity of noncompliance with SAIDI, considering factors such as the extent of deviation from established standards, the duration of noncompliance, and the impact on consumers, the Energy Bureau is inclined to impose LUMA a fine of $1.825 million dollars." *See* Notice at 2-3. It calculated the potential fine at $5,000 per day per 365 days/year. *Id.* at 3. The Energy Bureau further explained that the values at issue were "calculated by summing the monthly SAIDI (T&D) values for FY24 which encompasses the period of July 2023 through June 2024." *Id.*

As is known, LUMA reports its SAIDI values in Case No. 0007 on a quarterly basis. Case No. 0007 was initiated by the May 14th Order, which only contemplated that the process would be used to gather information and establish performance metrics for the electric power system. Then, on the May 21st Order, the Energy Bureau approved and established the baselines and benchmarks for all the performance metrics reported in Case No. 0007. In the May 21st Order, the Energy Bureau instructed PREPA and LUMA to start filing the quarterly reports, considering the approved metrics. Therefore, after the May 21st Order, the proceedings became exclusively a matter of gathering information regarding the electric power system.

The SAIDI value instated as a baseline in Case No. 0007, was calculated from PREPA's historical data for FY20 with a value of 1,243. Meanwhile, the aspirational benchmark SAIDI value was set at 102 minutes per month. *See* Resolution and Order dated May 21, 2021, issued in Case No. 0007. Moreover, the SAIDI values reported in Case No. 0007 have historically been reported monthly. After an Energy Bureau Resolution and Order of October 18, 2024, in Case No. 0007, the SAIDI values are now considered within a 12-month rolling average to align them to the performance metrics approved in Case No. NEPR-AP-2020-0025. *See* Resolution and Order dated October 18, 2024, issued in Case No. 0007.

The above shows that neither the Fiscal Year 2020 baseline nor the benchmark established by the Energy Bureau for SAIDI values is assessed on a daily basis. The Energy Bureau itself recognizes that the SAIDI values are calculated by summing the monthly values for a period that encompasses 12 months. For those reasons, it is illogical to conclude that LUMA may have incurred a daily violation that would warrant the imposition of a daily fine for 365 days. From the information available and reported in Case No. 0007, *it is impossible to calculate whether LUMA has surpassed a daily SAIDI value* because, as a threshold matter, there is no set daily SAIDI value baseline or benchmark. Second, the SAIDI values are reported in a monthly fashion. Considering that the SAIDI values are calculated by summing the monthly values for a period encompassing 12 months, assessing a monthly violation would also be impossible. At most, with the information at hand, the parameters set in Case No. 0007, and the method of calculating SAIDI values, the Energy Bureau is potentially entitled to determine that a violation of the Fiscal Year 2020 baseline or benchmark for SAIDI is strictly *limited to a single violation* amounting to the maximum allowed under Act 57-2014 and Section 12.01 of Regulation 8543.

E. LUMA's Request for a Hearing

As discussed above, it is unclear how the Energy Bureau analyzed LUMA's System Data in Case No. 0007, and the rationale behind its conclusion that there is a worsening trend in outage duration. Also, the Energy Bureau's decision to impose LUMA a significant fine of $1.825 million has no basis in the administrative record, when LUMA has not even been afforded the opportunity to illustrate this Energy Bureau on the current reliability trends for the T&D System and fully explain the circumstances and justification for the alleged decline in the SAIDI metric for FY24.

Therefore, in the event the Energy Bureau refuses to vacate the February 11th Order, LUMA respectfully requests a hearing where it can provide evidence and essential testimonies that may ease the Energy Bureau's concerns with the deterioration of the SAIDI metric, as permitted by Section 14.04 of Regulation 8543.

In compliance with Section 14.03 (C) of Regulation 8543, should the Energy Bureau decide to schedule a hearing, LUMA informs that the following individuals have knowledge and possess information in support of the arguments and defenses herein, and that all are under LUMA's control, rendering the issuance of summons unnecessary:

1. Mr. Kevin Burgemeister, Senior Vice President of Operations
2. Mr. Julio Aguilar, Vice President of Distribution Engineering and Reliability
3. Ms. Stacy O'Brien, Vice President of Grid Strategy
4. Dr. Richard Brown, Exponent; Expert Witness

WHEREFORE, LUMA respectfully requests that the honorable Energy Bureau **take notice** of the aforementioned; **vacate** the February 11th Order; and **decline** to impose a fine on LUMA. In the alternative, LUMA requests that the Energy Bureau **deem** that LUMA complied with the February 11th Order and schedule a hearing where LUMA can provide evidence and essential testimonies that may ease the Energy Bureau's concerns with the alleged deterioration of the SAIDI metric, as permitted by Section 14.04 of Regulation 8543.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 17th day of Mareh 2025.

DLA Piper (Puerto Rico) LLC
500 Calle de la Tanca, Suite 401
San Juan, PR 00901-1969
Tel. 787-945-9122 / 787-945-9132
Fax 939-697-6147 / 939-697-6102

Margarita Mercado Echegaray
RUA NÚM. 16,266
margarita.mercado@us.dlapiper.com

Yahaira De la Rosa Algarin
RUA NÚM. 18,061
yahaira.delarosa@us.dlapiper.com

Exhibit 1

Metrics Quarterly Report

Docket Number: NEPR-AI-2025-0001

Response: NOTICE-LUMA-AI-2025-0001-20250303-PREB-1

REQUEST

Response to Notice of Noncompliance **which should include:**

1. A Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent further deterioration of service quality.

2. Justification explaining the root causes of the noncompliance and any mitigating factors

3. Information listed in Section 14.03 of Regulation 8543.

RESPONSE

LUMA emphasizes its commitment to enhancing the reliability of Puerto Rico's electrical grid through strategic initiatives focused on improving service quality, minimizing outage duration, and strengthening the transmission and distribution (T&D) infrastructure. Since commencing operations, LUMA has accelerated critical infrastructure improvements, including replacing over 21,000 deteriorated utility poles capable of withstanding hurricane-class winds and deploying over 9,300 grid automation devices, while clearing over 5,500 miles of vegetation. LUMA has also replaced nine large substation transformers, over 65 transmission substation circuit breakers, and 31 distribution substation circuit breakers. These circuit breakers provide the essential service of quickly detecting and isolating disturbances, while protecting equipment. They are essential devices to maintain public safety by isolating and de-energizing faulty equipment on the grid. LUMA has also replaced over 100 damaged transmission poles and structures to harden the grid. In addition, during the Fiscal Year 2024 (FY2024), LUMA completed over 1,275 insulator replacement projects, more than 165 hot spot repairs, and over 285 switch repairs on the transmission system. These transmission investments have provided hardening and reduced the likelihood of critical equipment failures causing customer interruption. These efforts are vital to modernizing the T&D system and improving customer service.

Notwithstanding, operating in Puerto Rico makes supply chain challenges more impactful than peer utilities in the mainland US. Second, LUMA has experienced funding constraints that have resulted in LUMA receiving insufficient amounts to make the types of repairs, additions, and capital improvements that the system requires. In addition, the type of funding that LUMA currently primarily relies upon for capital needs – FEMA disaster restoration funding – is not intended to fund a general utility capital program and is not well-suited to that purpose. Instead, it has requirements, limitations, and timelines that serve the goal of ensuring funds are utilized to meet the Federal government's goals of storm resilience rather than meet the complex utility objectives of serving customers without discrimination, at reasonable rates, in alignment with the State or Territory's energy goals.

LUMA acknowledges that the T&D system continues to face significant challenges stemming from decades of underinvestment, deferred maintenance, and the impact of major weather events, all of which not only produced damage at the time but created a situation where the system continues to deteriorate without very rapid improvements. In alignment with peer utilities across the United States and the world, LUMA reports its reliability metrics, including the System Average Interruption Duration Index (SAIDI) in accordance with the IEEE Std. 1366-2012[1]. This standard recognizes the substantial influence of external factors on reliability metrics. It emphasizes the importance of assessing performance trends over a minimum five-year period to account for year-to-year variability and the impact of major events, as stated in IEEE 1366-2012 Section 5.3. By following these guidelines, utilities can comprehensively understand reliability trends, set realistic targets, and evaluate progress more effectively. This approach ensures that improvements in reliability metrics are sustainable and meaningful. For this reason, given the variability in weather and other external factors, with sporadic frequency in any one year, that reliability is recommended to be analyzed on a multi-year basis to identify the more meaningful underlying trends resulting from lack of investment and operational performance.

Importantly, as stated in IEEE Std 1782-2014[2] Section 5.2, reliability trends can be developed using various stratification methods. System indices are useful for understanding normal performance levels. A more granular reliability analysis is necessary to discern trends specific to certain geographies, environmental conditions, equipment types, or other stratification criteria. This is important when conducting comparisons, and it is crucial to recognize that random events can potentially lead to misleading conclusions if comparisons are not performed in the right context. The highlighted IEEE standards clearly indicate that using short periods to compare or establish baselines is not recommended. An approach that does not consider these aspects can provide a skewed vision of the system by not considering isolated incidents or anomalies, which may not accurately reflect long-term trends.

For this reason, LUMA considers that focusing on one fiscal year, specifically Fiscal Year 2023 (FY2023), as the basis for comparing reliability performance with FY2024 can be particularly misleading. The catastrophic effects of Hurricane Fiona in FY2023 created an extraordinary impact on the system, excluding major event days from that period from the reliability metrics. As discussed above, this is a standard exclusion per IEEE Std. 1366-2012; however, it can also make comparing the results to FY2024 challenging without considering the impact of Hurricane Fiona on the data. Likewise, the comparison between FY2023 and FY2024 reliability metrics is inherently problematic due to the extraordinary disruptions caused by Hurricane Fiona in FY2023, which led to the exclusion of major event days from reliability calculations, as per IEEE Std. 1366-2012. This exclusion creates a significant disparity in the data, making it challenging to evaluate FY2024 performance without accounting for the catastrophic impact of Hurricane Fiona on system reliability.

With these considerations, and in alignment with the guidance of IEEE Std. 1366-2012, LUMA undertook a comprehensive review of FY2023 that involved the statistical impact of catastrophic events, such as

[1] See Attachment A, IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Std 1366™-2012.

[2] See Attachment B, IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events, IEEE Std 1782™-2014.

Hurricane Fiona, on reliability metrics. The analysis takes into consideration the SAIDI performance trend prior to Hurricane Fiona. The goal of the analysis was to determine an approximate value of SAIDI under normal operations and degradation conditions for the period excluded from the metrics due to Hurricane Fiona. The analysis result provided an approximate SAIDI value of 1,378 minutes for FY2023[3]. While direct comparisons between fiscal years can be inherently complex, this adjustment is crucial for accurately analyzing performance trends and mitigating data skewing due to catastrophic events. As such, the revised SAIDI of 1,378 indicates a 4% deviation between FY2024 and FY2023.

This comparison between FY2023 and FY2024 reveals a complex reality. While the 4% deviation in SAIDI performance might seem minor, it underscores a significant concern: the system is still deteriorating. This deterioration is exacerbated by years of underinvestment and inadequate maintenance practices, which have cumulatively eroded the reliability of our T&D infrastructure. Each piece of failed equipment can impact customers directly and lead to more stress on the grid at large. This deviation between FY2023 and FY2024 indicates the continued need for aggressive T&D investment to counter the current rate of degradation and the effects of years of underinvestment and prior poor maintenance practices.

In light of these challenges, it is crucial to approach performance measurement and target-setting with a nuanced perspective. While baselines are essential for tracking progress and change over time, using them as targets can be misleading and counterproductive. Baselines represent the current state or historical performance, which may not reflect the future state of the system. Moreover, baselines established at the beginning may not account for changes in circumstances or unforeseen challenges during system operation due to weather and grid conditions. More so when the basis for that baseline is dated and does not reflect the current status of the system. For effective target-setting, using a baseline period of approximately five years is recommended, as this timeframe provides a balanced view of historical performance while minimizing the impact of outdated data as recommended per Standard IEEE 1366-2012 Section 5.3. This approach allows a more accurate reflection of current system realities and constraints. Thus, if an objective comparison of performance is to be drawn, it is crucial to establish realistic targets, considering the current system realities rather than relying solely on dated baseline data that does not contemplate current constraints on the system.

In addition, the Puerto Rico Energy Bureau (PREB), on February 11, 2025, Resolution and Order, used an annual baseline and performance to suggest a daily fine for non-compliance on SAIDI, which fails to properly understand the nature of this metric, as explained above. There is neither a daily SAIDI target nor a daily SAIDI metric to perform a daily comparison to determine which range of days was performing and underperforming. Therefore, interpreting that LUMA was underperforming for the 365 days of FY2024 is problematic, and results in an inaccurate measure.

Direct Root Causes of FY2024 SAIDI Performance

The primary drivers behind the SAIDI for FY2024 are examined in the Customer Minutes Interruption (CMI) root cause analysis[4]. This analysis is crucial for identifying the underlying contributors to the causes of CMI, which enables us to focus our remediation efforts more effectively. By analyzing these, we can pinpoint specific areas where targeted interventions are needed, classifying them using the contributors'

---

[3] See Attachment C, Excel file named EventNorm_MathModel.

[4] See Attachment D for raw data used for the analysis. Excel file named Master_Log_Python.

categories suggested by IEEE 1782-2014 – another critical standard used by peer utilities internationally for system outages – providing valuable insights that guide the development of corrective action plans. These corrective action plans are designed to address the root causes of interruptions, ensuring that our efforts are aligned with the most critical needs of our system.

By leveraging this data-driven approach, we aim to enhance system reliability, reduce outage durations, and ultimately improve customer satisfaction. We conducted an analysis of the top contributors and indirect root causes affecting SAIDI and response times. As a result of this analysis, several critical areas that warrant further discussion are highlighted below, including equipment issues, vegetation management challenges, and weather-related factors. Additionally, the analysis revealed indirect causes that also impact SAIDI, providing a comprehensive understanding of the factors influencing grid reliability.

- Aging Equipment: A critical factor affecting SAIDI performance is the aging infrastructure. The average age of assets is increasing at a rate that exceeds LUMA's current ability to invest in replacements and upgrades due to funding constraints known to the Energy Bureau. Additionally, a significant portion of our major assets continue operating beyond their designed life expectancy because either LUMA has yet to receive significant quantities of equipment due to supply chain challenges, or LUMA is experiencing issues with receiving sufficient funding for those resources. Over the past fiscal year, this situation has contributed to the increase in unplanned outages, amplified maintenance demands, and further undermined overall system reliability. As the average age of critical assets such as poles, insulation, conductors, transformers, arresters, and switches continues to outpace investment rates, we have faced, and continue to face, increasing risk of equipment failures. This situation leads to longer restoration times, affecting crew availability and ultimately increasing SAIDI. The typical mean time to repair (MTTR)[5] required to restore equipment is notably high, often exceeding several hours due to the complexity of repairs and the need for specialized resources. Specifically, the MTTR for pole replacement is more than 8 hours. Similarly, service transformer MTTR typically requires more than 5 hours, while conductor MTTR generally takes more than 4 hours. These prolonged restoration times highlight the need for efficient maintenance strategies and infrastructure upgrades to reduce downtime and improve overall grid reliability. In context, note that the T&D infrastructure is severely degraded (see Table 1). This degradation has led to frequent equipment failures, contributing over 37% to system SAIDI, which creates cascading weaknesses across the system. These failures reduce the grid's operational flexibility, complicate standard utility testing and maintenance procedures, and shorten the life expectancy of connected assets. As a result, Puerto Rico's infrastructure experiences faults at a rate considerably higher than comparable utilities.

  To better understand and address these issues, it is crucial to analyze the underlying metrics that quantify system reliability. The failure rate is a key statistical measure that quantifies the number of outages or events within a standardized time frame, as normalized by utilities. This metric is essential for evaluating the performance of different asset classes within the system. To provide a comprehensive assessment, we considered three categories for measuring asset class failure rates. These are based on either mileage or asset quantity. Specifically, T&D failure rates were normalized by the total mileage of lines and overhead feeders, respectively. This approach allows for a consistent comparison of failure rates across different network configurations. In contrast, substation failure rates were normalized by the total quantity of assets, as detailed in Table 1 below.

In FY2024, the T&D System equipment-related events increased by 13% compared to FY2023, contributing to 780 million CMIs and adding 531 minutes to the SAIDI. Equipment-related events include any defective or malfunctioning components within the distribution system that cause customer interruptions. These failures accounted for over 37% of total system outages in FY2024, highlighting the urgent need for targeted investments in infrastructure upgrades and proactive maintenance.

In FY2024, LUMA spent fewer federal funds than had originally been budgeted due to a series of challenges, including unforeseen complexities experienced in the procurement process, delays in the design phases, and a new federal funding obligation process for first-of-its-kind projects.

Unless LUMA can access sufficient funds to execute critical repairs, the aging grid will continue to deteriorate, increasing the likelihood of system-wide failures and further compromising reliability[5]. Also, as previously stated in RFI-LUMA-MI-2020-0019-20241029-PREB-003, the current Base Rate, established in 2017, does not reflect the realities and related challenges of grid operation and is neither sufficient to remediate the effects of decades of mismanagement and despair of the system.

Table 1. Asset Class Failure Rate[6]

Asset Class	FY2022	FY2023	FY2024	Unit
Distribution Overhead	2.78	2.79	3.38	Events/mi/Year
Transmission Lines	0.21	0.17	0.22	Events/mi/Year
Substations	0.78	0.91	0.86	Events/Asset/Year

- Vegetation: The lack of vegetation clearance has significantly contributed to outages during storms and high-wind events. In FY2024, there was a 41% increase in vegetation-related events compared to FY2023, resulting in over 471 million CMIs. This surge directly impacted the SAIDI by adding more than 321 minutes to the overall system performance. The persistent issues with vegetation management can be largely attributed to a historical lack of properly planned maintenance programs. Insufficient financial resources have hindered effective vegetation clearance efforts for years, leaving power lines vulnerable to overgrowth. That lack of proactive management exacerbated the frequency and severity of outages, particularly during adverse weather conditions. Since the commencement of operations, LUMA has sought to overcome those significant vegetation challenges and the lack of funding by seeking and obtaining authority for $1.2 billion in federal hazard mitigation funds to reclaim overgrown rights-of-way. The combination of federal funding for clearing and the existing budget for vegetation maintenance was predicted to be adequate for FY2024 and through the subsequent 3-year business planning cycle to allow significant progress on the vegetation problem. However, large-scale federal

[5] See Attachment E, IEEE Recommended Practice for Analyzing Reliability Data for Equipment Used in Industrial and Commercial Power Systems.

[6] See Attachment F, A Review of the Reliability of Electric Distribution System Components_EPRI White Paper; Attachment G, Distribution System Component Failure Rates and Repair Times – An Overview.; and Attachment H, Excel file named System_AssetFailureRate.

funding obligation did not happen in FY2024 as expected. The initial approval for the concept of this first-ever type of program was required. After that, projects that include exacting maps of the individual rights-of-way to be cleared must be reviewed and approved. The first project was approved for distribution lines in the San Juan region, and, on implementation, it was discovered that cost data – which impacted all other projects – had to be revised, taking additional time to gather the data required for this never-before undertaken scope of work. As a result, LUMA had to rely solely on maintenance funds and less effective "hot spotting" techniques to manage the worst vegetation problems for another year.

The initial approved budget for vegetation management for system maintenance purposes has been $50 million per year for professional services (vendors performing vegetation management services). Although this has remained consistently flat at the beginning of each fiscal year, for FY2024, the PREB approved the reallocation of $6 million from the Operational Budget to increase vegetation management. Final spending varied for each year. For the fiscal year 2022 (FY2022), total spending was $50.9 million, FY2023 spending was $62.7 million, and FY2024 spending was $55.7 million. Miles trimmed or cleared (non-federally funded) for each year respectfully was 896 miles, 1,849 miles, and 1,464 miles for a total of 4,209 miles completed in 3 years. With a system of 16,113 overhead line miles, LUMA has been able to trim 26% of the overall system across a 3-year period with the non-federal budget allocation. LUMA has determined that even after completion of the federally funded clearing program, approximately $130 million in Operations & Maintenance funding will be required annually to properly maintain the rights-of-way on a 4-year maintenance cycle to prevent the regrowth of vegetation that would result in the loss of the benefits achieved through the federally funded clearing. These estimated amounts are more than current funding levels and show the large gap between the current state and what would be considered industry standard.

- Deferred Maintenance: Historical underinvestment in maintenance has resulted in a significant backlog of necessary repairs and upgrades within the T&D system. This underinvestment pattern has continued and has affected LUMA's ability to make crucial maintenance, thus leading to the current situation where aging infrastructure is increasingly susceptible to failures, leading to a higher frequency of outages and service interruptions. As assets age beyond their intended lifespan, the likelihood of equipment malfunctions rises, affecting reliability and placing additional strain on operational resources. The backlog of maintenance tasks includes critical repairs to aging utility poles, transformers, and circuit breakers essential for maintaining system integrity. The consequences of deferred maintenance due to underfunded initiatives extend beyond immediate operational challenges and pose long-term financial implications. Increased emergency repair costs can strain budgets further. To address these issues, it is imperative to prioritize investment in maintenance and upgrades. As an example, in our analysis from May 2022, it was noted that 67% of transformers were overdue for maintenance. This issue was exemplified by the fact that during the Fiscal Year 2021, only 13% of the planned transformer and breaker maintenance was completed by February 2021. This significant backlog highlights the need for enhanced maintenance strategies supported with adequate funding, to ensure that critical equipment is properly serviced, reducing the risk of failures and improving overall grid reliability. Currently, maintenance work being completed on the system is on a priority basis and is fully reactive, focused on addressing equipment that has failed or is causing repeat outages. Through analysis, LUMA identifies the "worst performing" equipment and targets our limited resources to address these critical priorities. LUMA has been able to find efficiencies and enhance existing maintenance programs with year-over-year improvements in the quantities of repairs being completed. For example, transmission line insulator replacements, a common failure point on the transmission system; LUMA completed 824 structures in FY2023 but was able to increase that to 1,275 structures in FY2024. However, even with the improvements in maintenance tasks completed, the overall system continues to degrade at a faster rate than repairs. To make substantive progress in system reliability, LUMA needs to transition to a preventative maintenance program that addresses all areas of the system, not just immediate critical priorities. A full preventative maintenance program that adheres to industry standards has been designed by LUMA; however, it requires funding to implement. The financial needs of this program have been addressed in the future rate case that LUMA is currently preparing.

- Weather Factors: SAIDI is significantly influenced by weather conditions, leading to increased outage durations and frequency. With severe weather events, such as storms, the short-term impact is more noticeable, yet the long-term effects sometimes are not. However, those impacts result in an increase in abnormal circuit configurations, temporary solutions, and reduced inventory that impacts scheduled and non-scheduled work.

  In FY2024, LUMA observed a notable CMI contribution of more than 6% on SAIDI due to adverse weather conditions (Weather and Lightning categories), resulting in prolonged outages across our service area. Weather-related factors, such as heavy rain, strong winds, and frequent lightning strikes, caused significant infrastructure damage, including downed power lines, broken poles, and malfunctioning equipment. These conditions extended restoration times and required extensive efforts from crews to repair or replace damaged components, with the mean time to repair power equipment ranging from 4 to 10 hours. Additionally, the impact of vegetation, such as tree branches and foliage becoming entangled in power lines, further worsened the situation and increased the frequency of outages. Extreme temperatures also added stress to the grid, leading to higher demand and equipment failures, further prolonged outage durations, and intensified severity.

  To better understand these impacts, LUMA analyzed historical outage data in relation to weather patterns. This analysis indicates that specific weather events contribute disproportionately to SAIDI increments. For example, during weather events, outages can extend significantly due to debris removal, equipment repairs, and the need for comprehensive safety assessments before restoring power. Ensuring the well-being of our workforce is paramount, and we take additional measures to safeguard them while they work under challenging conditions. During bad weather conditions, for example, wind and rain, we implement enhanced safety protocols to protect our personnel from hazards such as fallen power lines, flooded areas, and debris. This includes conducting thorough additional risk assessments before each task. We prioritize heat stress prevention in cases of excessive heat by providing regular hydration breaks and shaded rest areas when necessary. Our teams are also trained to recognize the signs of heat-related illnesses and immediately act if any symptoms are observed. These safety measures are essential and cannot be compromised. While they may contribute to longer outage durations, they are critical for ensuring that our personnel return home safely at the end of each day.

  Recognizing the influence of weather on our performance metrics is crucial for developing effective strategies to enhance grid resilience. By investing in infrastructure improvements, such as upgrading aging assets and enhancing vegetation management practices, we aim to mitigate the effects of severe weather on our system reliability. While weather conditions will always pose challenges to our operations, understanding their effect on SAIDI enables us to take proactive measures that enhance our service reliability and ultimately improve customer satisfaction.

Indirect Causes of FY2024 SAIDI Performance

SAIDI provides a comprehensive view of service reliability by quantifying the total average duration of interruptions experienced by customers over a specified period, as discussed above. However, SAIDI performance is also influenced by a range of indirect factors that complicate its improvement. Key among these factors is operational improvement, such as safety, which is essential for ensuring safe operations but indirectly impacts SAIDI performance. For instance, implementing enhanced safety protocols temporarily diverts resources or requires additional time for compliance checks, which influences outage response times. Another indirect factor that affects restoration times is fleet availability, which directly impacts response times to outages. Additionally, as discussed above, budget constraints limit the ability to invest in necessary infrastructure upgrades and maintenance, leading to a higher likelihood of equipment failures and prolonged outages. The procurement process challenges also play a significant role. Delays in acquiring critical materials or equipment due to lengthy procurement cycles hinder timely repairs and upgrades, further exacerbating SAIDI. Moreover, material availability issues stemming from supply chain disruptions or shortages lead to extended delivery times for essential components, complicating efforts to restore service quickly. Understanding these indirect factors is crucial when developing effective strategies to enhance grid reliability and improve SAIDI performance. By addressing these challenges proactively, utilities can better manage operational risks and ensure more reliable service delivery to their customers.

- Safety Improvements: As established in RFI-LUMA-MI-2019-0007-20241226-PREB-Attachment A-4, safety is a top priority for LUMA. From the beginning of our operations, we identified the need to strengthen our capabilities in this vital area, investing significant time and resources in training our field employees and adopting the industry's best practices. These efforts ensure strict adherence to essential safety protocols when working on electrical systems. Examples of processes and practices that have been introduced, enhanced, trained, and compliance-mandated include equipotential bonding and grounding practices, pre-work hazard assessments and mitigation, job site tailgate meetings, safety briefings and stand-downs, and three-way communication. As LUMA implemented these safety-focused changes in both our practices and organizational culture, we experienced some impact on productivity that may have led to longer repair and restoration times. Efforts being driven to improve response efficiency and effectiveness will offset these increases over time.

- Material Shortage: The T&D system faces escalating challenges due to material shortages, exacerbated by lengthy procurement processes, as LUMA's stated in RFI-LUMA-MI-2020-0019-20241029-PREB-005, and a persistent lack of investment. These factors combine to severely hinder the modernization and maintenance efforts essential for a reliable energy supply. Historical underfunding has already created a significant backlog of needed upgrades and repairs, and the current landscape further complicates any attempts to address these issues.

  LUMA, in anticipation of the material shortage challenges, after commencement, aggressively began the processes of ordering long lead material items. LUMA's foresight to this challenge means that materials that can take 2 years or more to procure are beginning to arrive on the island. LUMA has been able to start replacing critical equipment, such as power transformers and transmission breakers. For example, LUMA has now ordered over 80 Power Transformers, with the first units scheduled to arrive in April 2025. These units will be installed as expeditiously as resources allow to replace transformers that have already failed on the system and have been out of service for months and years, replace transformers that are beyond their reliable service life and condition, and provide hazard mitigation as components in federal projects. These replacement activities are critical for the stability and reliability of the transmission system and to protect customers from widespread and long-duration outages. The reality is that this type of equipment takes significant time to procure, and the related work cannot proceed until the replacement equipment arrives. This long lead element, in conjunction with limited to no critical spares on hand at transition time, has hampered the ability to move forward with critical component replacements.

Another consideration is the shortage of replacement parts for repairs. Due to the aged equipment, restoration times are often extended due to the lack of parts or non-inventory items. Component or auxiliary equipment failures also cause significant reliability issues. These tend to be even more challenging to procure due to age and lack of manufacturer support. Additionally, this situation may even require specialized manufacturing to be able to restore major equipment.

The lack of investment in the T&D system significantly compounds the combination of material shortages and lengthy procurement processes. Without adequate financial resources allocated for upgrades, LUMA continues to be challenged while attempting to acquire necessary materials in a timely manner. Delays in acquiring essential materials and equipment disrupt scheduled maintenance, leading to deferred repairs that further degrade the system. Additionally, prolonged outages directly impact customer satisfaction, economic stability, and public safety. In summary, the combination of these factors creates a self-perpetuating cycle of system degradation, increased outages, and escalating costs.

- Transmission and Distribution Fleet Availability: Table 2, which contains year-to-date data, shows that 57% of fleet assets exceeded their expected service life. The challenge of aging fleet assets significantly impacts our ability to attend to outages promptly and efficiently. With a growing number of vehicles operating beyond their expected service life, our fleet experiences increased maintenance needs and unexpected downtime. The increased downtime of older vehicles directly affects our outage response times. When vehicles are unavailable due to maintenance, it strains our resources and can delay our ability to reach outage locations, especially in critical situations. LUMA is currently behind the capital investment profile outlined in the Fleet Management Plan and related T&D Fleet Program Brief to return the Fleet assets to industry-standard useful lives (e.g., seven years for Light Vehicles, 10 years for Heavy Vehicles, and 15 to 20 years for Offroad Equipment and Trailers). There is a requirement to add 337 units to accommodate the anticipated increase in headcount within operations and to reduce costs related to rental purchase option vehicles and rented equipment. However, the abovementioned constraints have hindered LUMA's ability to invest at the pace needed to align with the capital investment profile for these activities. LUMA continues to enhance vehicle maintenance programs to stretch the life expectancy of existing vehicles as well as rent vehicles to fill equipment gaps. However, both tactics put additional strain on the Operations & Maintenance funding. LUMA has taken steps to build out the necessary capital funding to meet the fleet needs within the upcoming rate case submission.

Table 2. Available Fleet Assets

Category	Total	Within Expected Service Life	Beyond Expected Service Life	
	Quantity		Quantity	%
Bucket Trucks	349	250	99	28%
Diggers	98	75	23	23%
Equipment	268	118	150	56%
Heavy Duty	247	78	169	68%
Light Duty	966	332	634	66%
Trailers	233	71	162	70%
Total	2161	924	1237	57%

Corrective Action Plans

LUMA's Corrective Action Plan is designed to implement comprehensive measures to improve the SAIDI and prevent further deterioration of service quality. This plan addresses the underlying issues contributing to service interruptions by identifying and addressing both direct and indirect root cause factors that impact reliability. Through a deep analysis, we have pinpointed specific areas for improvement and developed targeted programs to address these issues. As already established, LUMA analyzes historical outage data to identify recurring causes of interruptions, such as aging infrastructure, vegetation management issues, and equipment failures. We can significantly reduce the frequency and duration of outages by addressing these root causes through targeted maintenance and upgrades.

Table 3. Corrective Action Plan Workstreams

Impacted Root Cause	Workstream	FY2024 Key Achievements	Timeline for Implementation	Expected Improvement
'egetation Jutages	Vegetation Management and Capital Clearing Implementation	Clearing over 1,500 miles of distribution and transmission lines; completing the fifth round of substation herbicide treatment; completing 70 percent of substations treated on the sixth round; and starting the federally funded vegetation clearing initiative with San Juan Group A obligations.	Vegetation-clearing efforts are planned to occur over the next four years (between FY2025 and FY2028). After the Vegetation Reset program, LUMA will establish and maintain a four-year cycle for power line maintenance.	Vegetation Management and Capital Clearing workstream estimates at the end of the fiscal year 2028 indicate an overall reduction of 400 million in CMI.
Aging Equipment	Distribution Line Rebuild	Submitting one initial Scope of Work (SOW) for distribution underground work; submitting 18 detailed SOWs representing 98 feeders; dividing feeder project groups into individual 151 priority feader projects to speed up the obligation process; and completing 35 area plans of 71 areas outlined.	Workstream goal is to replace over 200 miles of distribution lines from FY2026 to FY2029.	Workstream Initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 100 million in CMI and a minimum of 600 million CMI avoided by the end of the program.

Aging Equipment	**Distribution Pole and Conductor Repair**	Installation of more than 4,300 poles and submitting six initial SOWs and 12 detailed SOWs to obtain FEMA funding obligation for 3,872 poles. We received funds obligation for two projects totalizing 301 poles.	Workstream goal is to replace up to 24,000 Critical Poles by FY2036.	Workstream initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 180 million in CMI and a minimum of 320 million CMI avoided by the end of the program.
Aging Equipment	**Transmission Line Rebuild**	Replacing six transmission structures on one of the worst-performing transmission lines; submitting 20 initial SOWs to address system reliability improvements to the PREB; submitting four detailed SOWs to FEMA; evaluating proposed projects to assess the scopes with the highest impact and dividing those transmission line rebuilds into multiple projects bounded by adjacent substations to drive efficiency and project execution.	Transmission Line Rebuilds efforts are planned to start in FY2027. A total of 15 transmission lines are to be impacted by the end of FY2028. By the end of FY2035, LUMA expects to finalize a total of 49 Transmission Line Segments.	Transmission Line Rebuild and Transmission Line Pole replacement workstreams initiatives estimates at the end of fiscal year 2028 indicate an overall reduction of 18 million in CMI and a minimum of 130 million CMI avoided by the end of the program.
Aging Equipment	**Transmission Priority Pole Replacement**	Replacing 27 structures, installing seven pole bases, making 164 critical repairs, designing 108 structures, and submitting 10 initial SOWs and nine detailed SOWs to FEMA for an obligation of funds for 53 structure replacements and 52 critical repairs.	Transmission Line Pole Replacement efforts are planned to start in FY2026. LUMA plans to impact over 200 transmission line structures by the end of FY2028.	Transmission Line Rebuild and Transmission Line Pole replacement workstreams initiatives estimates at the end of fiscal year 2028 indicate an overall reduction of 18 million in CMI and a minimum of 130 million CMI avoided by the end of the program.
Aging Equipment	**Substation Rebuild**	Installation and energizing breakers in Aguirre, Añasco, Daguao, Sabana Llana, Palmer, and Venezuela substations. We also installed transformers in Sabana Llana, Monacillos Aguada, and Venezuela. Submitted eleven detailed SOWs to FEMA for substation rebuild and minor repair project group as well as for the Acacias substation relocation.	Substation Rebuilds efforts are planned to start in FY2026. A total of 38 substations are to be impacted by the end of FY2028.	Substation Rebuild workstream initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 67 million in CMI and a minimum of 250 million CMI avoided by the end of the program.
Improve Restoration Times and Customer Interrupted Avoidance	**Distribution Automation**	Installation of 1,381 circuit fault indicators, 212 three-phase reclosers, 407 single-phase reclosers, and 458 cutouts. Additionally, we conducted 3,393 fuse optimizations. We completed protection settings for 190 feeders, performed reliability analysis for more than 500 feeders, completed work order packages for 2,881 devices, and submitted 13 detailed SOWs.	LUMA plans to continue installing more than 11,000 automation devices in the next two years (FY2025-FY2026), including three-phase reclosers, single-phase reclosers, communicating fault current indicators, and distribution protective devices.	Distribution Automation initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 230 million in CMI and a minimum of 430 million CMI avoided by the end of the program.

<u>Restoration Time Improvements</u>

Resource Availability and Development

LUMA has acted throughout the Fiscal Year 2025 (FY2025) to continue increasing the onboarding and deployment of experienced workers both for reliability work and outage responses. Shortly after commencement, LUMA undertook an aggressive upskilling program to bring the level of qualification of LUMA employees up to expected industry standards. The upskilling program was completed in November 2023, when LUMA had graduated 225 lineworkers to fully qualified status. During FY2025, LUMA continued to increase the onboarding and deployment of experienced workers both for reliability work and outage responses. These efforts have been multi-pronged and include the following:

- **Utility Fieldworkers:** It is important to note that LUMA has more than 1,000 utility field workers, including lineworkers, in its Operations team. These are composed of approximately 60% ex-PREPA employees who have deep experience and knowledge of the Puerto Rico electric system and, with LUMA, have received industry-standard training through upskilling programs resulting in trade certification and qualification that ensures LUMA's technical craft workers are fully equipped to work safely and effectively.

- **Lineworker Apprenticeship Program**: This Program is focused on developing and growing local talent. Traditionally, an apprenticeship program cannot deliver qualified workers for approximately four years as the apprentice works through the eight stages of development from pre-apprenticeship through to the completion of the Apprentice Period. As of now, there are 216 apprentice lineworkers enrolled in LUMA's program, with the first students already starting to graduate in 2025, with the first graduate in February. This marks a significant milestone in our commitment to developing a skilled workforce dedicated to enhancing the reliability and resilience of Puerto Rico's energy infrastructure.

- **Substation Technician, Underground Residential Distribution Technician, and Cyber Security Technician programs**: These programs were added to the apprenticeships being offered, with the Underground Residential Distribution program being the most advanced out of these three programs. Having properly trained and certified craft workers ensures that LUMA can complete technical work on the system in a safe and effective manner. Currently, LUMA has 31 Underground Residential Distribution, 57 Substation, and 7 Cyber Security apprentices.

- **Off-island hiring programs**: LUMA has instituted off-island hiring programs both within the US mainland and internationally. The US mainland program has resulted in more than 25 trade-certified worker hires for Powerline and Substation Technicians, focused on attracting workers who have left Puerto Rico and previously worked for PREPA.

- LUMA has continually onboarded contractors to supplement our internal workforce with qualified personnel when needed. This includes local engineering resources to conduct system analysis and develop work order packages to execute key reliability work throughout the island by internal resources and construction contractors (i.e., transmission and distribution pole, transmission and distribution line rebuild, transmission and distribution substation reliability improvements, distribution automation, and vegetation work).

LUMA has a strong need to continue building qualified resources into the future to continue expanding and executing the repair and maintenance programs needed to improve system reliability. LUMA estimates that an approximate additional 200 internal craft workers plus contracted resources are required. Future growth plans depend on increased funding in both Operations & Maintenance and Non-Federally Funded Capital budgets. Underfunding these programs remains a significant concern and limitation to executing the needed plans.

Fleet Availability

As part of our analysis, we identified fleet availability as an indirect root cause impacting our operational efficiency. To address this, LUMA has implemented comprehensive strategies that simultaneously meet immediate operational needs and ensure long-term sustainability. Our current fleet management practices are designed to optimize vehicle readiness and minimize downtime, which is essential for ensuring our vehicles are available to support critical operations.

- **Strategic Replacement Planning:** Since its commencement, LUMA has implemented a well-structured fleet replacement strategy to maintain high fleet availability and reduce downtime. Investing in timely asset replacements can significantly minimize the operational disruptions associated with aging vehicles. Regular assessments of fleet conditions and the establishment of realistic vehicle life cycles enable proactive asset replacement before failures occur, thereby enhancing reliability and operational efficiency. In line with this strategy, LUMA executed an order for 30 additional bucket trucks in FY2025. These new vehicles will bolster our fleet capacity and reduce the downtime caused by aging or underperforming assets. By integrating these trucks into our operations, we aim to improve our response times to system outages, ensuring faster restoration of service and greater customer satisfaction.

- **Preventive Maintenance Schedule:** Since FY2022, LUMA has also implemented a robust preventive maintenance schedule crucial for keeping our vehicles in optimal condition. Routine inspections, oil changes, tire rotations, and brake checks should be scheduled based on manufacturer guidelines and historical performance data. This proactive approach minimizes unexpected breakdowns and ensures that vehicles are always ready for service.

- **Utilization of Advanced Fleet Management Software:** The implementation of LUMA's Fleet Management Software was successfully completed during FY2023. The adoption of fleet management software can streamline operations by providing real-time tracking, maintenance scheduling, and data analytics. These tools enable us to monitor vehicle utilization effectively, identify maintenance needs early, and optimize resource allocation. We can make informed decisions that enhance fleet availability by leveraging data-driven insights.

- **Telematics Technology Integration:** During FY2025, LUMA integrated telematics technology for real-time vehicle performance and driver behavior monitoring. This data can help identify inefficiencies in driving practices that may lead to increased vehicle wear and tear. We can improve overall vehicle longevity and availability by addressing these issues through targeted training programs and feedback mechanisms.

By implementing these strategies, we can significantly enhance our fleet's availability, ensuring that vehicles are ready to meet operational demands while improving overall efficiency and customer service. Prioritizing these initiatives will reduce downtime and contribute to the long-term sustainability of our fleet operations.

Material Shortage

As outlined in response to RFI-LUMA-MI-2020-0019-20241029-PREB-006, LUMA has implemented several measures to streamline procurement processes and effectively mitigate challenges related to material shortages. At the start of FY2024, a revised Procurement Manual was published to establish clearer guidelines for every stage of the procurement process, ensuring that all teams follow a common framework. This manual provides a structured approach to managing procurement activities, from assessing requirements to delivering results.

LUMA engaged an external partner to assess the procurement department and lead a comprehensive transformation to drive further improvements. This initiative included redefining the department's organizational structure, establishing clear goals, and identifying key success factors to drive change. Additionally, LUMA appointed a new Chief Procurement Officer with extensive experience in leadership roles, specializing in financial and strategic planning, global sourcing strategies, business negotiation, and contract life cycle management. In addition to our ongoing procurement process improvements, the following initiatives are designed to help address material shortages effectively:

- **Enhanced Sourcing Strategies:** LUMA is establishing a dedicated sourcing team focused on improving the drafting of scopes of work and streamlining event execution. This team will work closely with suppliers to anticipate and mitigate material shortages by diversifying supply chains and negotiating favorable terms.
- **Workforce Augmentation:** By the end of FY2025, LUMA will have hired 15 operational procurement specialists and five internal controls specialists. These additions will support the reassessment and implementation of updated processes and procedures, strengthening the department's capacity to manage material procurement efficiently and address shortages proactively.
- **Technology Integration:** LUMA will implement a new workflow management tool designed to improve process adherence, provide better visibility into performance metrics, and facilitate tracking of key performance indicators. This tool will enable real-time monitoring of material availability and procurement timelines, helping to identify potential shortages early and manage them effectively.
- **Collaboration and Alignment**: The procurement department will foster greater alignment with other business functions, promoting closer collaboration to ensure that material needs are anticipated and met promptly. This integrated approach will help prevent delays caused by material shortages, supporting smoother operations and reducing the risk of supply chain disruptions.

By focusing on these strategic improvements, LUMA aims to enhance its procurement operations, address material shortages more effectively, and build a more efficient and effective procurement organization.

Efforts are underway to improve the Puerto Rico Power System, with the root causes of current challenges identified. However, addressing these issues requires investments, materials, and resources, which have been challenging to secure due to existing budget constraints and process limitations. Despite ongoing efforts, the current budget allocation remains insufficient to maintain the grid, let alone improve key metrics. The Corrective Action Plan is being implemented to address these challenges. However, budget constraints may impact the implementation timeline, affecting projections for improvement in customer minutes avoided. It is crucial to be aware that these projections may be delayed if budget limitations persist, underscoring the need for sustainable funding solutions.

GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: NOTICE OF NONCOMPLIANCE WITH THE PUERTO RICO ENERGY PUBLIC POLICY	**CASE NO. NEPR-AI-2025-0001** **SUBJECT: LUMA Noncompliance with SAIDI Metric**

CERTIFICATION IN SUPPORT OF MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER OF FEBRUARY 11, 2025

The undersigned, Julio Aguilar, of legal age, married, executive, and resident of Guaynabo Puerto Rico, hereby declares:

1. My personal circumstances are as stated above.

2. I have been the Vice President of Distribution Engineering and Reliability in LUMA Energy ServCo, LLC ("LUMA") since August 19, 2024.

3. In my current role as Vice President of Distribution Engineering and Reliability at LUMA, I am in charge of Reliability. This department is tasked with analysis outage data and reporting LUMA reliability Metrics.

4. Pursuant to Section 5.6 of the *Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement* ("T&D OMA") executed on June 22, 2020, by and between LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public Private Partnerships Authority, as administrator, LUMA, as an agent of PREPA, submits quarterly reports to the Puerto Rico Energy Bureau ("Energy Bureau") containing information regarding PREPA's transmission and distribution system, ("T&D System"), including LUMA's performance based on certain metrics/indicators ("System Data").

5. On July 22, 2024, LUMA submitted to the Energy Bureau a Quarterly Report with System Data for the months of April through June 2024 ("July Quarterly Report") in case number NEPR-MI-2019-0007.

6. Upon receipt of the July Quarterly Report and after several procedural incidents, on February 11, 2025, the Energy Bureau issued a Resolution and Order, opening the instant proceeding ("February 11th Order"). The Energy Bureau expressed that because LUMA's reported SAIDI[1] value for Fiscal Year 2024 ("FY24") surpassed both the value reported for Fiscal Year 2023 and the regulatory threshold, it represented a failure to meet the reliability standards established to ensure an electric system that is resilient and responsive to consumer needs in alignment with the principles set forth in the Puerto Rico Energy Transformation and RELIEF Act, Act 57-2014 and the Puerto Rico Energy Public Policy Act, Act 17-2019. Based on this, the Energy Bureau issued a Notice of Non-Compliance to ensure corrective action and manifested its inclination to impose LUMA a fine of $1.825 million.

7. Through the February 11th Order, the Energy Bureau instructed LUMA to file a response including (i) a Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent future deterioration of service quality; and (ii) justification explaining the root causes of the noncompliance and any mitigating factors.

8. For the purposes of complying with the February 11th Order, I participated in and oversaw the preparation of the document titled *Responses to February 11, 2025, Resolution and Order; Metrics Quarterly Report Docket Number: NEPR-AI-2025-0001* ("LUMA's Response"), which is attached as **Exhibit 1** of *LUMA's Motion in Compliance with Resolution and Order of February 11, 2025, and Request for Hearing* ("Motion in Compliance"). As required by the Energy Bureau,

[1] System Average Interruption Duration Index.

LUMA's Response provides detailed information to this Energy Bureau on the direct and indirect root causes of FY24 SAIDI performance, and the corrective action plans delineated by LUMA to improve the SAIDI value and prevent further deterioration, along with timelines for implementation of each workstream. To provide full context to the Energy Bureau, LUMA's Response also provides a comprehensive account of the challenges that LUMA has encountered since assuming the operation and maintenance of the T&D System under the T&D OMA, which, notwithstanding LUMA's best efforts, have contributed negatively to its reliability performance. It also summarizes initiatives implemented during Fiscal Year 2025, which may improve outage responses and SAIDI values going forward.

9. I certify that LUMA's Response was jointly prepared by LUMA's personnel, with either collective or personal knowledge of the data, events, circumstances, programs, initiatives, and plans identified therein and based on information that is being kept in LUMA's records in the regular course of business.

10. I execute this Certification as an addendum to the Motion in Compliance to be filed by LUMA before the Energy Bureau, whose arguments and requests for remedies I fully support.

11. I certify that the foregoing is true and correct to the best of my knowledge, information, and belief.

In San Juan, Puerto Rico, this 16th of March, 2025.

Julio Aguilar

Julio Aguilar

GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: NOTICE OF NONCOMPLIANCE WITH THE PUERTO RICO ENERGY PUBLIC POLICY	CASE NO. NEPR-AI-2025-0001 SUBJECT: LUMA Noncompliance with SAIDI Metric

CERTIFICATION IN SUPPORT OF MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER OF FEBRUARY 11, 2025

The undersigned, Kevin Burgemeister, of legal age, married, executive, and resident of San Juan, Puerto Rico, hereby declares:

1. My personal circumstances are as stated above.

2. I have been the Senior Vice President of Operations in LUMA Energy ServCo, LLC ("LUMA") since January 20, 2024.

3. In my current role as Senior Vice President of Operations at LUMA, I am in charge of LUMA operations. This department is tasked with the operation and maintenance of the transmission and distribution system of Puerto Rico.

4. Pursuant to Section 5.6 of the *Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement* ("T&D OMA") executed on June 22, 2020, by and between LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public Private Partnerships Authority, as administrator, LUMA, as an agent of PREPA, submits quarterly reports to the Puerto Rico Energy Bureau ("Energy Bureau") containing information regarding PREPA's transmission and distribution system, ("T&D System"), including LUMA's performance based on certain metrics/indicators ("System Data").

5. On July 22, 2024, LUMA submitted to the Energy Bureau a Quarterly Report with System Data for the months of April through June 2024 ("July Quarterly Report") in case number NEPR-MI-2019-0007.

6. Upon receipt of the July Quarterly Report and after several procedural incidents, on February 11, 2025, the Energy Bureau issued a Resolution and Order, opening the instant proceeding ("February 11th Order"). The Energy Bureau expressed that because LUMA's reported SAIDI[1] value for Fiscal Year 2024 ("FY24") surpassed both the value reported for Fiscal Year 2023 and the regulatory threshold, it represented a failure to meet the reliability standards established to ensure an electric system that is resilient and responsive to consumer needs in alignment with the principles set forth in the Puerto Rico Energy Transformation and RELIEF Act, Act 57-2014 and the Puerto Rico Energy Public Policy Act, Act 17-2019. Based on this, the Energy Bureau issued a Notice of Non-Compliance to ensure corrective action and manifested its inclination to impose LUMA a fine of $1.825 million.

7. Through the February 11th Order, the Energy Bureau instructed LUMA to file a response including (i) a Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent future deterioration of service quality; and (ii) justification explaining the root causes of the noncompliance and any mitigating factors.

8. For the purposes of complying with the February 11th Order, I participated in and oversaw the preparation of the document titled *Responses to February 11, 2025, Resolution and Order; Metrics Quarterly Report Docket Number: NEPR-AI-2025-0001* ("LUMA's Response"), which is attached as **Exhibit 1** of *LUMA's Motion in Compliance with Resolution and Order of February 11, 2025, and Request for Hearing* ("Motion in Compliance"). As required by the Energy Bureau,

[1] System Average Interruption Duration Index.

LUMA's Response provides detailed information to this Energy Bureau on the direct and indirect root causes of FY24 SAIDI performance, and the corrective action plans delineated by LUMA to improve the SAIDI value and prevent further deterioration, along with timelines for implementation of each workstream. To provide full context to the Energy Bureau, LUMA's Response also provides a comprehensive account of the challenges that LUMA has encountered since assuming the operation and maintenance of the T&D System under the T&D OMA, which, notwithstanding LUMA's best efforts, have contributed negatively to its reliability performance. It also summarizes initiatives implemented during Fiscal Year 2025, which may improve outage responses and SAIDI values going forward.

9. I certify that LUMA's Response was jointly prepared by LUMA's personnel, with either collective or personal knowledge of the data, events, circumstances, programs, initiatives, and plans identified therein and based on information that is being kept in LUMA's records in the regular course of business.

10. I execute this Certification as an addendum to the Motion in Compliance to be filed by LUMA before the Energy Bureau, whose arguments and requests for remedies I fully support.

11. I certify that the foregoing is true and correct to the best of my knowledge, information, and belief.

In San Juan, Puerto Rico, this 14 of March, 2025.

Kevin Burgemeister

GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: NOTICE OF NONCOMPLIANCE WITH THE PUERTO RICO ENERGY PUBLIC POLICY	CASE NO. NEPR-AI-2025-0001 SUBJECT: LUMA Noncompliance with SAIDI Metric

CERTIFICATION IN SUPPORT OF MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER OF FEBRUARY 11, 2025

The undersigned, Anastasia M. O'Brien, of legal age, executive, and resident of Oak Park, Illinois, hereby declares:

1. My personal circumstances are as stated above.

2. I have been the Vice President of Grid Strategy in LUMA Energy ServCo, LLC ("LUMA") since May 1, 2023.

3. In my current role as Vice President of Grid Strategy at LUMA, I am in charge of _overseeing Federal funding opportunities, including FEMA public assistance, and investment strategy. This group is tasked with responsibility for administering government grants, loans and other financial assistance programs. This includes:

- grants management, such as formulation of projects proposed to FEMA and application for grants from the DOE;
- compliance and oversight to ensure compliance with regulations and guidelines, monitoring how the funds are used and conducting audits as necessary;
- technical assistance to project managers and other outside groups involved with the process;

- policy development related to funding priorities;
- collaboration with relevant government entities and others involved in the process; and
- Develop, implement and manage investment strategies for Capital Programs.

4. Pursuant to Section 5.6 of the *Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement* ("T&D OMA") executed on June 22, 2020, by and between LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public Private Partnerships Authority, as administrator, LUMA, as an agent of PREPA, submits quarterly reports to the Puerto Rico Energy Bureau ("Energy Bureau") containing information regarding PREPA's transmission and distribution system, ("T&D System"), including LUMA's performance based on certain metrics/indicators ("System Data").

5. On July 22, 2024, LUMA submitted to the Energy Bureau a Quarterly Report with System Data for the months of April through June 2024 ("July Quarterly Report") in case number NEPR-MI-2019-0007.

6. Upon receipt of the July Quarterly Report and after several procedural incidents, on February 11, 2025, the Energy Bureau issued a Resolution and Order, opening the instant proceeding ("February 11th Order"). The Energy Bureau expressed that because LUMA's reported SAIDI[1] value for Fiscal Year 2024 ("FY24") surpassed both the value reported for Fiscal Year 2023 and the regulatory threshold, it represented a failure to meet the reliability standards established to ensure an electric system that is resilient and responsive to consumer needs in alignment with the principles set forth in the Puerto Rico Energy Transformation and RELIEF Act, Act 57-2014 and the Puerto Rico Energy Public Policy Act, Act 17-2019. Based on this, the Energy

[1] System Average Interruption Duration Index.

Bureau issued a Notice of Non-Compliance to ensure corrective action and manifested its inclination to impose LUMA a fine of $1.825 million.

7. Through the February 11th Order, the Energy Bureau instructed LUMA to file a response including (i) a Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent future deterioration of service quality; and (ii) justification explaining the root causes of the noncompliance and any mitigating factors.

8. For the purposes of complying with the February 11th Order, I participated in and oversaw the preparation of the document titled *Responses to February 11, 2025, Resolution and Order; Metrics Quarterly Report Docket Number: NEPR-AI-2025-0001* ("LUMA's Response"), which is attached as **Exhibit 1** of *LUMA's Motion in Compliance with Resolution and Order of February 11, 2025, and Request for Hearing* ("Motion in Compliance"). As required by the Energy Bureau, LUMA's Response provides detailed information to this Energy Bureau on the direct and indirect root causes of FY24 SAIDI performance, and the corrective action plans delineated by LUMA to improve the SAIDI value and prevent further deterioration, along with timelines for implementation of each workstream. To provide full context to the Energy Bureau, LUMA's Response also provides a comprehensive account of the challenges that LUMA has encountered since assuming the operation and maintenance of the T&D System under the T&D OMA, which, notwithstanding LUMA's best efforts, have contributed negatively to its reliability performance. It also summarizes initiatives implemented during Fiscal Year 2025, which may improve outage responses and SAIDI values going forward.

9. I certify that LUMA's Response was jointly prepared by LUMA's personnel, with either collective or personal knowledge of the data, events, circumstances, programs, initiatives, and

plans identified therein and based on information that is being kept in LUMA's records in the regular course of business.

10. I execute this Certification as an addendum to the Motion in Compliance to be filed by LUMA before the Energy Bureau, whose arguments and requests for remedies I fully support.

11. I certify that the foregoing is true and correct to the best of my knowledge, information, and belief.

In San Juan, Puerto Rico, this 14th of March, 2025.

Stacy O'Brien

Stacy O'Brien

IEEE STANDARDS ASSOCIATION

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power & Energy Society

Sponsored by the
Transmission and Distribution Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

31 May 2012

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

IEEE Guide for Electric Power Distribution Reliability Indices

Sponsor

Transmission and Distribution Committee
of the
IEEE Power & Energy Society

Approved 14 May 2012

IEEE-SA Standards Board

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

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

PDF: ISBN 978-0-7381-7275-0 STD97250
Print: ISBN 978-0-7381-7381-8 STDPD97250

Notice and Disclaimer of Liability Concerning the Use of IEEE Documents: IEEE Standards documents are developed within the IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association (IEEE-SA) Standards Board. IEEE develops its standards through a consensus development process, approved by the American National Standards Institute, which brings together volunteers representing varied viewpoints and interests to achieve the final product. Volunteers are not necessarily members of the Institute and serve without compensation. While IEEE administers the process and establishes rules to promote fairness in the consensus development process, IEEE does not independently evaluate, test, or verify the accuracy of any of the information or the soundness of any judgments contained in its standards.

Use of an IEEE Standard is wholly voluntary. IEEE disclaims liability for any personal injury, property or other damage, of any nature whatsoever, whether special, indirect, consequential, or compensatory, directly or indirectly resulting from the publication, use of, or reliance upon any IEEE Standard document.

IEEE does not warrant or represent the accuracy or content of the material contained in its standards, and expressly disclaims any express or implied warranty, including any implied warranty of merchantability or fitness for a specific purpose, or that the use of the material contained in its standards is free from patent infringement. IEEE Standards documents are supplied "AS IS."

The existence of an IEEE Standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard. Every IEEE standard is subjected to review at least every ten years. When a document is more than ten years old and has not undergone a revision process, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE standard.

In publishing and making its standards available, IEEE is not suggesting or rendering professional or other services for, or on behalf of, any person or entity. Nor is IEEE undertaking to perform any duty owed by any other person or entity to another. Any person utilizing any IEEE Standards document, should rely upon his or her own independent judgment in the exercise of reasonable care in any given circumstances or, as appropriate, seek the advice of a competent professional in determining the appropriateness of a given IEEE standard.

Translations: The IEEE consensus development process involves the review of documents in English only. In the event that an IEEE standard is translated, only the English version published by IEEE should be considered the approved IEEE standard.

Official Statements: A statement, written or oral, that is not processed in accordance with the IEEE-SA Standards Board Operations Manual shall not be considered the official position of IEEE or any of its committees and shall not be considered to be, nor be relied upon as, a formal position of IEEE. At lectures, symposia, seminars, or educational courses, an individual presenting information on IEEE standards shall make it clear that his or her views should be considered the personal views of that individual rather than the formal position of IEEE.

Comments on Standards: Comments for revision of IEEE Standards documents are welcome from any interested party, regardless of membership affiliation with IEEE. However, IEEE does not provide consulting information or advice pertaining to IEEE Standards documents. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments. Since IEEE standards represent a consensus of concerned interests, it is important to ensure that any responses to comments and questions also receive the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to comments or questions except in those cases where the matter has previously been addressed. Any person who would like to participate in evaluating comments or revisions to an IEEE standard is welcome to join the relevant IEEE working group at http://standards.ieee.org/develop/wg/.

Comments on standards should be submitted to the following address:

Secretary, IEEE-SA Standards Board
445 Hoes Lane
Piscataway, NJ 08854
USA

Photocopies: Authorization to photocopy portions of any individual standard for internal or personal use is granted by The Institute of Electrical and Electronics Engineers, Inc., provided that the appropriate fee is paid to Copyright Clearance Center. To arrange for payment of licensing fee, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; +1 978 750 8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

Notice to users

Laws and regulations

Users of IEEE Standards documents should consult all applicable laws and regulations. Compliance with the provisions of any IEEE Standards document does not imply compliance to any applicable regulatory requirements. Implementers of the standard are responsible for observing or referring to the applicable regulatory requirements. IEEE does not, by the publication of its standards, intend to urge action that is not in compliance with applicable laws, and these documents may not be construed as doing so.

Copyrights

This document is copyrighted by the IEEE. It is made available for a wide variety of both public and private uses. These include both use, by reference, in laws and regulations, and use in private self-regulation, standardization, and the promotion of engineering practices and methods. By making this document available for use and adoption by public authorities and private users, the IEEE does not waive any rights in copyright to this document.

Updating of IEEE documents

Users of IEEE Standards documents should be aware that these documents may be superseded at any time by the issuance of new editions or may be amended from time to time through the issuance of amendments, corrigenda, or errata. An official IEEE document at any point in time consists of the current edition of the document together with any amendments, corrigenda, or errata then in effect. In order to determine whether a given document is the current edition and whether it has been amended through the issuance of amendments, corrigenda, or errata, visit the IEEE-SA Website at http://standards.ieee.org/index.html or contact the IEEE at the address listed previously. For more information about the IEEE Standards Association or the IEEE standards development process, visit the IEEE-SA Website at http://standards.ieee.org/index.html.

Errata

Errata, if any, for this and all other standards can be accessed at the following URL: http://standards.ieee.org/findstds/errata/index.html. Users are encouraged to check this URL for errata periodically.

Patents

Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken by the IEEE with respect to the existence or validity of any patent rights in connection therewith. If a patent holder or patent applicant has filed a statement of assurance via an Accepted Letter of Assurance, then the statement is listed on the IEEE-SA Website at http://standards.ieee.org/about/sasb/patcom/patents.html. Letters of Assurance may indicate whether the Submitter is willing or unwilling to grant licenses under patent rights without compensation or under reasonable rates, with reasonable terms and conditions that are demonstrably free of any unfair discrimination to applicants desiring to obtain such licenses.

Essential Patent Claims may exist for which a Letter of Assurance has not been received. The IEEE is not responsible for identifying Essential Patent Claims for which a license may be reqnired, for conducting inquiries into the legal validity or scope of Patents Claims, or determining whether any licensing terms or conditions provided in connection with submission of a Letter of Assurance, if any, or in any licensing agreements are reasonable or non-discriminatory. Users of this standard are expressly advised that determination of the validity of any patent rights, and the risk of infringement of such rights, is entirely their own responsibility. Further information may be obtained from the IEEE Standards Association.

Participants

At the time this IEEE guide was completed, the Distribution Reliability Working Group had the following membership:

Rodney Robinson*, *Chair (2011-present)*
Cheryl A. Warren*, *Chair (1991-2011)*
John McDaniel*, *Vice Chair*
Val Werner, *Secretary*

John Ainscough
Razon Alvin
Daniel Arden
Greg Ardrey
Ignacio Ares
Dave Asgharian
John Banting
Philip Barker
Bill Becia
Roy Billinton
Chantal Bitton
David Blankenheim
James D. Bouford*
James Bundren
James Burke
Thomas Callsen
Mark Carr
Patrick Carroll
Heide Caswell
Bill Chisholm
Richard D. Christie*
Rob Christman
G. Larry Clark
Mike Clodfelder
James Cole
Larry Conrad
Betsy Coppock
Ed Cortez
Herve Delmas
Chuck DeNardo
Frank Doherty
April Dombrook
R. Clay Doyle
Jeff Duff
Charlie Fijnvandratt
Fredric Friend
Keith Frost
Anish Gaikwad
David Gilmer
Manuel Gonzalez
John Goodfellow
Tom Grisham
Tom Gutwin
Donald Hall
Keith Harley
Harry Hayes
Charles Heising
Richard Hensel
James Hettrick
Ray Hisayasu
Alex Hoffman
Tao Hong
Ian Hoogendan
Mike Hyland
Cindy Janke
Allan Jirges
Joshua Jones
Robert Jones
Morteza Khodaie
Mark Koyna
Frank Lambert
Dave Lankutis
Larry Larson
Jim Lemke
Jack Leonard
Giancarlo Leone
Gene Lindholm
Ray Lings
Nick Loehlein
Ning Lu
J. C. Mathieson
Ethan Matthes
Ed Mayer
Tom McCarthy
Tom McDermott
Mark McGranaghan
Kale Meade
Tom Menten
Mathieu Mougeot
Terry Nielsen
Gregory Obenchain
Ray O'Leary
Gregory Olson
Jamie Ortega
Anil Pahwa
Milorad Papic
Marc Patterson
Dan Pearson
Mike Pehosh
Charles Perry
Ray Piercy
Jeff Pogue
Steve Pullins
Mike Rafferty
Caryn Riley
D. Tom Rizy
Tim Rogelstad
Ziolo Roldan
Robert Rusch
David Russo
D. Daniel Sabin
Robert Saint
N. D. R. Sarma
Josh Schellenberg
David J. Schepers*
Steven Schott
Andy Schwalm
Ken Sedziol
Matt Seeley
Mike Shepherd
David Shibilia
Tom Short
Cheong Siew
Georges Simard
Jeff Smith
Rusty Soderberg
John Spare
Joshua Stallings
Lee Taylor
Mark Thatcher
Casey Thompson
Betty Tobin
Tom Tobin
S. S. (Mani) Venkata
Joseph Viglietta*
Marek Waclawiak
Juli Wagner
Reigh Walling
David Wang
Daniel J. Ward
Greg Welch
Charlie Williams*
John Williams
Taui Willis
Mike Worden
Bo Yang

*Acknowledgments: The following members were primary authors and data analyzers for the development of the 2.5 Beta Methodology that is used for identification of Major Event Days:

James D. Bouford
Richard D. Christie
Dan Kowalewski
John McDaniel
Rodney Robinson
David J. Schepers
Joseph Viglietta
Cheryl A. Warren
Charlie Williams

The following members of the individual balloting committee voted on this guide. Balloters may have voted for approval, disapproval, or abstention.

William Ackerman
Michael Adams
Ali Al Awazi
Saleman Alibhay
Robert Arno
Thomas Basso
Wallace Binder
Robin Blanton
James D. Bouford
Gustavo Brunello
William Bush
William Byrd
Mark Carr
Robert Christman
James Cleary
James Cole
Larry Conrad
Timothy Croushore
Gary Donner
April Dornbrook
Randall Dotson
Neal Dowling
Donald Dunn
Gary Engmann
Rabiz Foda
Fredric Friend
David Gilmer
Mietek Glinkowski
Waymon Goch
Edwin Goodwin
Thomas Grebe
Randall Groves
Ajit Gwal
Donald Hall
Dennis Hansen
Jeffrey Hartenberger
David Haynes
Lee Herron
James Hettrick
Scott Hietpas
Werner Hoelzl
Joseph Jancauskas
Jeffrey Jelzer
Gael Kennedy
Yuri Khersonsky
Morteza Khodaie
Joseph L. Koepfinger
Jim Kulchisky
Chung-Yiu Lam
Paul Lindemulder
Greg Luri
William McBride
John McDaniel
John McDonald
Gary Michel
C. Michael Miller
Joydeep Mitra
Jerry Murphy
Arthur Neubauer
Michael S. Newman
Joe Nims
Lorraine Padden
Mirko Palazzo
Bansi Patel
Michael Roberts
Rodney Robinson
Charles Rogers
Thomas Rozek
D. Daniel Sabin
Robert Saint
Bartien Sayogo
Dennis Schlender
Robert Schuerger
Gil Shultz
Christine Siebenshuh
Cheong Siew
James Smith
Jerry Smith
John Spare
Joshua Stallings
Gary Stoedter
Lee Taylor
Mark Thatcher
Eric Udren
John Vergis
Mark Walton
Daniel J. Ward
Lee Welch
Kenneth White
Jonathan Woodworth
Jian Yu
Francisc Zavoda

When the IEEE-SA Standards Board approved this guide on 14 May 2012, it had the following membership:

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.

Contents

IEEE Guide for Electric Power Distribution Reliability Indices

IMPORTANT NOTICE: IEEE Standards documents are not intended to ensure safety, health, or environmental protection, or ensure against interference with or from other devices or networks. Implementers of IEEE Standards documents are responsible for determining and complying with all appropriate safety, security, environmental, health, and interference protection practices and all applicable laws and regulations.

This IEEE document is made available for use subject to important notices and legal disclaimers. These notices and disclaimers appear in all publications containing this document and may be found under the heading "Important Notice" or "Important Notices and Disclaimers Concerning IEEE Documents." They can also be obtained on request from IEEE or viewed at http://standards.ieee.org/IPR/disclaimers.html.

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 unifonnity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among ntilities. 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 shonld 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
$\mathbf{CN}_{(k\geq n)}$	Total number of customers who have experienced *n* or more sustained interruptions during the reporting period
$\mathbf{CN}_{(k\geq S)}$	Total number of customers that experienced S or more hours duration
$\mathbf{CN}_{(k\geq T)}$	Total number of customers that experienced T or more hours duration
$\mathbf{CNT}_{(k\geq n)}$	Total number of customers who have experienced *n* or more sustained interruptions and momentary interruption events during the reporting period
E	Event
$\mathbf{IM}_i$	Number of momentary interruptions
$\mathbf{IM}_E$	Number of momentary interruption events
k	Number of interruptions experienced by an individual customer in the reporting period
$\mathbf{L}_i$	Connected kVA load interrupted for each interruption event
$\mathbf{L}_T$	Total connected kVA load served
$\mathbf{N}_i$	Number of interrupted customers for each sustained interruption event during the reporting period
$\mathbf{N}_{mi}$	Number of interrupted customers for each momentary interruption event during the reporting period

N_T Total number of customers served for the area

r_i Restoration time for each interruption event

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).

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

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).

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

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).

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

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

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

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).

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

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

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

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).

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

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

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

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).

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

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

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

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

3.2.7 $\mathbf{CEMI_n}$: 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).

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

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

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

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:

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

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

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

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 iu Eq. (19).

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

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

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \tag{20}$$

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).

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

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

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \tag{22}$$

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).

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

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 distribntion 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.

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

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

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

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.

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

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

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

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

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

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.

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

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

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

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

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

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

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).

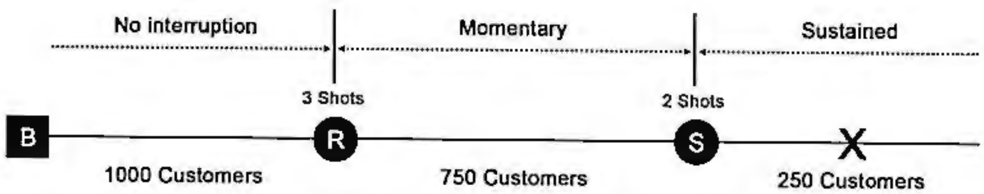


Figure 1—Sample system two

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.

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

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

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

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.

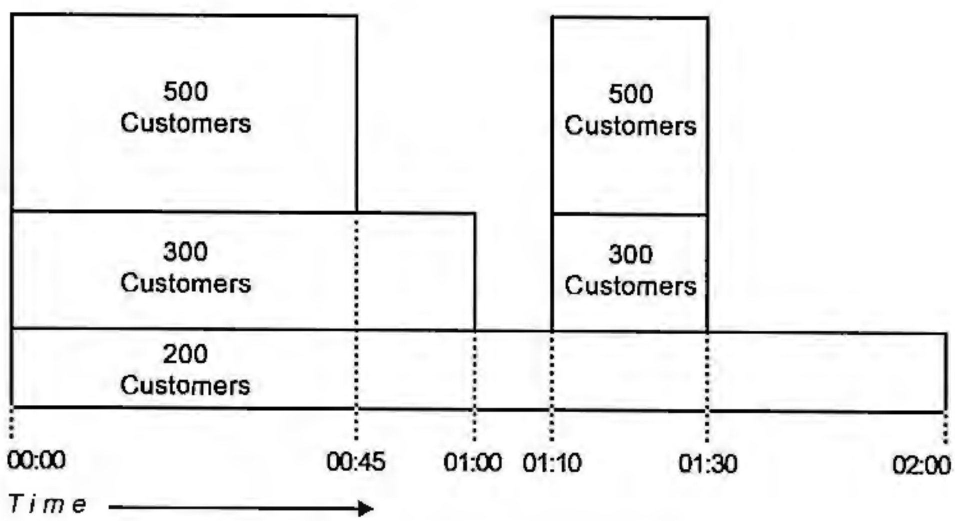


Figure 2—Step restoration time chart

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.

[B1] Balijapelli, N., Venkata, S. S., Christie, R. D., "Predicting Distribution System Performance Against Regulatory Reliability Standards." *IEEE Transactions on Power Delivery*, vol. 19, no. 1, pp. 350-356, January 2004.

[B2] Billinton, R., Allan, R. N., *Reliability Evaluation of Power Systems*, Plenum Press, 1984.

[B3] Billinton, R., Allan, R., Salvaderi, L., *Applied Reliability Assessment in Electric Power Systems*, IEEE Press, 1991.

[B4] Brown, R. E., *Electric Power Distribution Reliability*, Marcel Dekker, 2002.

[B5] Capra, R. A., Gangel, M. W., Lyon, S. V., "Underground Distribution System Design for Reliability," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-88: 6, June 1969, pp. 834-42.

[B6] Christie, R. D., "Statistical Classification of Major Event Days in Distribution System Reliability," *IEEE Transactions on Power Delivery*, vol. 18, no.4, pp. 1336-1341, October 2003.

[B7] EPRI RP-1356-1, EL-2018, "Development of Distribution System Reliability and Risk Analysis Models," vol. 2, August 1981.

[B8] IEEE/PES Working Group on System Design. "A Nationwide Survey of Distribution Reliability Measurement Practices," Paper No.98 WM 218.

[B9] IEEE Std 859, IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States of Electrical Transmission Facilities.[3]

[B10] Kottegoda, N. T., Rosso, R., *Statistics, Probability, and Reliability for Civil and Environmental Engineers*, The McGraw-Hill Companies, 1997.

[B11] Marinello, C. A., "A Nationwide Survey of Reliability Practices," Presented at EEI T&D Committee Meeting, Hershey, PA, October 20, 1993.

[3] IEEE publications are available from The Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (http://standards.ieee.org/).

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):

$$p(\text{SAIDI} > T) = \int_{T}^{\infty} pdf(\text{SAIDI})d\text{SAIDI} \tag{B.1}$$

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

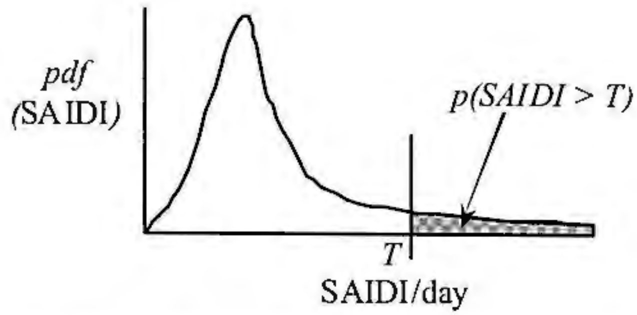


Figure B.1—The area under the probability density of function pdf (SAIDI)

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.

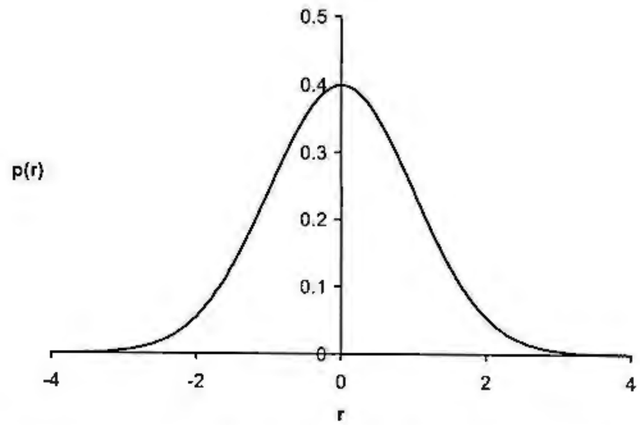


Figure B.2—Gaussian, or normal, probability distribution

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

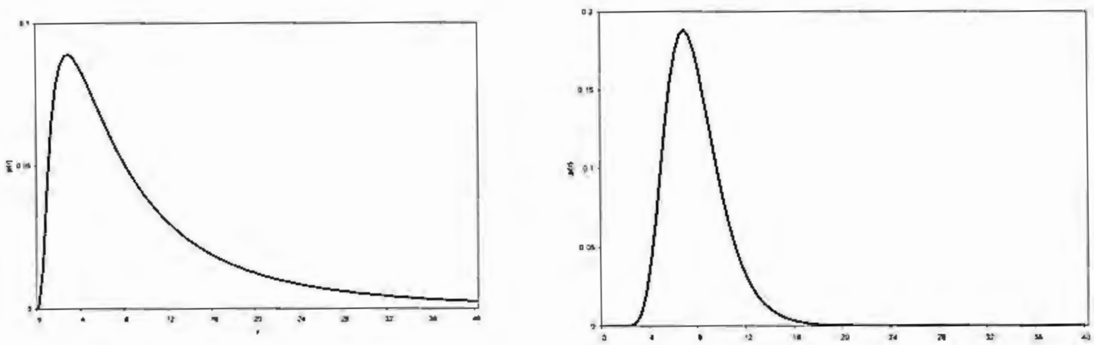
n	p
1	0.15866
2	0.02275
3	0.00135
6	$9.9\text{x}10^{-10}$

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.



(a) (b)

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-uormal 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.

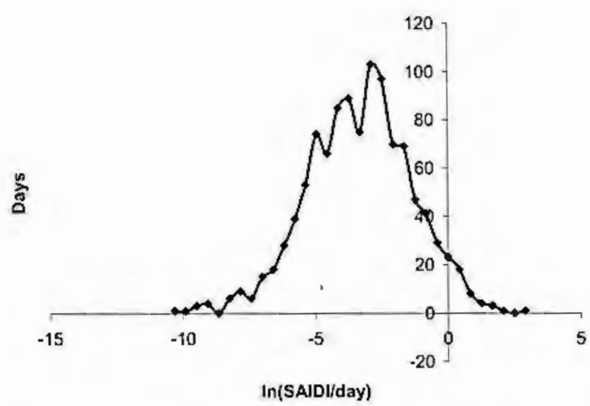


Figure B.4—Histogram of the natural logs of three years of daily SAIDI data from anonymous utility two supplied by the Distribution System Design Working Group

A consequence of the log-normality of daily reliability data is that the three sigma conditious 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.

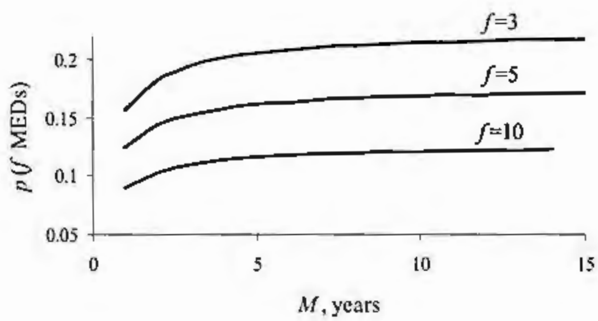


Figure B.5—Probability of exactly *f* new MEDs in the next year of data using *M* years of historical data

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.

IEEE STANDARDS ASSOCIATION

IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events

IEEE Power and Energy Society

Sponsored by the
Transmission and Distribution Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1782™-2014

IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events

Sponsor

Transmission and Distribution Committee
of the
IEEE Power and Energy Society

Approved 27 March 2014

IEEE-SA Standards Board

Abstract: Reliability of electric power systems remains an important societal issue. While transmission disturbances draw national attention and scrutiny, service interruptions at the distribution level are the primary concern of the end-use customer and their regulatory and governmental representatives. Much effort has been expended in developing methods to uniformly and consistently quantify the reliability of distribution service based on electric system performance. However, the results of a nationwide survey of recorded information used for calculating distribution reliability indices performed in 1998 by the Working Group on System Design (now Distribution Reliability) indicate that significant inconsistencies exist in the data, categorization of that data, and in the collection processes used within the industry. This guide discusses the collection, categorization, and use of information related to electric power distribution interruption events and will be used in the development of industry guidelines. This guide presents a minimal set of data and a consistent categorization structure that, when used in combination with IEEE Std 1366™, will promote consistency in how the industry collects data for the purpose of benchmarking distribution system performance.

Keywords: benchmarking, data collection, IEEE 1782™, outage management systems, power distribution reliability, reliability management, sampling methods

---

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

PDF: ISBN 978-0-7381-8974-1 STD98571
Print: ISBN 978-0-7381-8975-8 STDPD98571

Important Notices and Disclaimers Concerning IEEE Standards Documents

IEEE documents are made available for use subject to important notices and legal disclaimers. These notices and disclaimers, or a reference to this page, appear in all standards and may be found under the heading "Important Notice" or "Important Notices and Disclaimers Concerning IEEE Standards Documents."

Notice and Disclaimer of Liability Concerning the Use of IEEE Standards Documents

IEEE Standards documents (standards, recommended practices, and guides), both full-use and trial-use, are developed within IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association ("IEEE-SA") Standards Board. IEEE ("the Institute") develops its standards through a consensus development process, approved by the American National Standards Institute ("ANSI"), which brings together volunteers representing varied viewpoints and interests to achieve the final product. Volunteers are not necessarily members of the Institute and participate without compensation from IEEE. While IEEE administers the process and establishes rules to promote fairness in the consensus development process, IEEE does not independently evaluate, test, or verify the accuracy of any of the information or the soundness of any judgments contained in its standards.

IEEE does not warrant or represent the accuracy or content of the material contained in its standards, and expressly disclaims all warranties (express, implied and statutory) not included in this or any other document relating to the standard, including, but not limited to, the warranties of: merchantability; fitness for a particular purpose; non-infringement; and quality, accuracy, effectiveness, currency, or completeness of material. In addition, IEEE disclaims any and all conditions relating to: results; and workmanlike effort. IEEE standards documents are supplied "AS IS" and "WITH ALL FAULTS."

Use of an IEEE standard is wholly voluntary. The existence of an IEEE standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard.

In publishing and making its standards available, IEEE is not suggesting or rendering professional or other services for, or on behalf of, any person or entity nor is IEEE undertaking to perform any duty owed by any other person or entity to another. Any person utilizing any IEEE Standards document, should rely upon his or her own independent judgment in the exercise of reasonable care in any given circumstances or, as appropriate, seek the advice of a competent professional in determining the appropriateness of a given IEEE standard.

IN NO EVENT SHALL IEEE BE LIABLE FOR ANY DIRECT, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, OR CONSEQUENTIAL DAMAGES (INCLUDING, BUT NOT LIMITED TO: PROCUREMENT OF SUBSTITUTE GOODS OR SERVICES; LOSS OF USE, DATA, OR PROFITS; OR BUSINESS INTERRUPTION) HOWEVER CAUSED AND ON ANY THEORY OF LIABILITY, WHETHER IN CONTRACT, STRICT LIABILITY, OR TORT (INCLUDING NEGLIGENCE OR OTHERWISE) ARISING IN ANY WAY OUT OF THE PUBLICATION, USE OF, OR RELIANCE UPON ANY STANDARD, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGE AND REGARDLESS OF WHETHER SUCH DAMAGE WAS FORESEEABLE.

Translations

The IEEE consensus development process involves the review of documents in English only. In the event that an IEEE standard is translated, only the English version published by IEEE should be considered the approved IEEE standard.

Official statements

A statement, written or oral, that is not processed in accordance with the IEEE-SA Standards Board Operations Manual shall not be considered or inferred to be the official position of IEEE or any of its committees and shall not be considered to be, or be relied upon as, a formal position of IEEE. At lectures, symposia, seminars, or educational courses, an individual presenting information on IEEE standards shall make it clear that his or her views should be considered the personal views of that individual rather than the formal position of IEEE.

Comments on standards

Comments for revision of IEEE Standards documents are welcome from any interested party, regardless of membership affiliation with IEEE. However, IEEE does not provide consulting information or advice pertaining to IEEE Standards documents. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments. Since IEEE standards represent a consensus of concerned interests, it is important that any responses to comments and questions also receive the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to comments or questions except in those cases where the matter has previously been addressed. For the same reason, IEEE does not respond to interpretation requests. Any person who would like to participate in revisions to an IEEE standard is welcome to join the relevant IEEE working gronp.

Comments on standards should be submitted to the following address:

Secretary, IEEE-SA Standards Board
445 Hoes Lane
Piscataway, NJ 08854 USA

Laws and regulations

Users of IEEE Standards documents should consult all applicable laws and regulations. Compliance with the provisions of any IEEE Standards document does not imply compliance to any applicable regulatory reqnirements. Implementers of the standard are responsible for observing or referring to the applicable regulatory requirements. IEEE does not, by the publication of its standards, intend to urge action that is not in compliance with applicable laws, and these documents may not be construed as doing so.

Copyrights

IEEE draft and approved standards are copyrighted by IEEE under U.S. and international copyright laws. They are made available by IEEE and are adopted for a wide variety of both public and private uses. These include both use, by reference, in laws and regulations, and use in private self-regulation, standardization, and the promotion of engineering practices and methods. By making these documents available for use and adoption by public authorities and private users, IEEE does not waive any rights in copyright to the documents.

Photocopies

Subject to payment of the appropriate fee, IEEE will grant users a limited, non-exclusive license to photocopy portions of any individual standard for company or organizational internal use or individual, non-commercial use only. To arrange for payment of licensing fees, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; +1 978 750 8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

Updating of IEEE Standards documents

Users of IEEE Standards documents should be aware that these documents may be superseded at any time by the issuance of new editions or may be amended from time to time through the issuance of amendments, corrigenda, or errata. An official IEEE document at any point in time consists of the current edition of the document together with any amendments, corrigenda, or errata then in effect.

Every IEEE standard is subjected to review at least every ten years. When a document is more than ten years old and has not undergone a revision process, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE standard.

In order to determine whether a given document is the current edition and whether it has been amended through the issuance of amendments, corrigenda, or errata, visit the IEEE-SA Website at http://ieeexplore.ieee.org/xpl/standards.jsp or contact IEEE at the address listed previously. For more information about the IEEE-SA or IEEE's standards development process, visit the IEEE-SA Website at http://standards.ieee.org.

Errata

Errata, if any, for all IEEE standards can be accessed on the IEEE-SA Website at the following URL: http://standards.ieee.org/findstds/errata/index.html. Users are encouraged to check this URL for errata periodically.

Patents

Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken by the IEEE with respect to the existence or validity of any patent rights in connection therewith. If a patent holder or patent applicant has filed a statement of assurance via an Accepted Letter of Assurance, then the statement is listed on the IEEE-SA Website at http://standards.ieee.org/about/sasb/patcom/patents.html. Letters of Assurance may indicate whether the Submitter is willing or unwilling to grant licenses under patent rights without compensation or under reasonable rates, with reasonable terms and conditions that are demonstrably free of any unfair discrimination to applicants desiring to obtain such licenses.

Essential Patent Claims may exist for which a Letter of Assurance has not been received. The IEEE is not responsible for identifying Essential Patent Claims for which a license may be required, for conducting inquiries into the legal validity or scope of Patents Claims, or determining whether any licensing terms or conditions provided in connection with submission of a Letter of Assurance, if any, or in any licensing agreements are reasonable or non-discriminatory. Users of this standard are expressly advised that determination of the validity of any patent rights, and the risk of infringement of such rights, is entirely their own responsibility. Further information may be obtained from the IEEE Standards Association.

Participants

At the time this IEEE guide was completed, the System Design Working Group had the following membership:

Rodney Robinson*, *Chair (2011-Present)*
John McDaniel, *Vice Chair*
Val Werner*, *Secretary*

Barney Adler
John Ainscough
Dave Albergine
Daniel Arden
Greg Ardrey
Ignacio Ares
Davood Asgharian
Jim Ashkar
Dustin Ballacy
John Banting
Karie Barczakk
Philip Barker
Ryan Bartlett
Ed Beavers
Bill Becia
James Benaglio
Lina Bertling
William Beutler
Tom Bialek
Roy Billinton
Chantal Bitton
David Blankenheim
John Bolinger
Jim Bouford*
Vilet Bounnam
Stephane Brule
Jason Bundren
James Burke
William Burley
Brandy Burnett
Thomas Callsen
Manuel Camara
Mark Carr
Patrick Carroll
Heide Caswell*
Cliff Cayer
Donald M. Chamberlin
M. L. Chan
Baden Chatterton
Dave Chetwynd
Bill Chisholm
Tony Chou
Rich Christie
Rob Christman
George Clark
Mike Clodfelder
James Cole
Betsy Coppock
Larry Conrad
Grace Couret
Tim Croushore
Bill Daily
Jeff Deal
Herve Delmas
Chuck DeNardo
Fred Dennert
Frank Doherty
April Dornbrook
R. Clay Doyle
Jeff Duff
Herman Dyal
Mike Engel
Russ Erlich
Joe Eto
Charlie Fijnvandraat
Emily Fisher
Doug Fitchett
Fred Friend
Keith Frost*
Justin Fuith
Anish Gaikwad
David Gilmer
Manuel Gonzalez
John Goodfellow
John Gordon
Tom Grisham
Tom Gutwin
Don Hall*
Jane Hammes
Randy Harlas
Keith Harley
Harry Hayes
David Haynes
Eric Helt
Jim Hettrick
Ray Hisayasu
Paul Hodges
Alex Hofmann
Tao Hong
Ian Hoogendam
Bob Howes
Mike Hyland
Cindy Janke
Allan Jirges
Joshua Jones
Robert Jones
Mark Kemper
John Kennedy
Mort Khodaie
Ann Kimber
Margaret Kirk
Mark Konya*
Frank Lambert
Dave Lankutis*
Ken Lau
Roger Lee
Jim Lemke
Jack Leonard
Giancarlo Leone
Gene Lindholm
Ray Lings
Nick Loehlein
Andrew Lozano
Susan Lovejoy
Ning Lu
Robert Manning
Ethan Matthes
Ed Mayer
Tom McCarthy
Tom McDermott
Mark McGranaghan
Steve McHardy
Kale Meade
Tom Menten
Bill Montgomery
J. C. Mathieson
Mathieu Mougeot
Jerry Murray
Peter Nedwick
Mike Nekola
Terry Nielsen
Denise Nikoloff
Gregory Obenchain
Ray O'Leary
Gregory Olson
Jamie Ortega
Anil Pahwa
Milorad Papic
Marc Patterson
Dan Pearson
Mike Pehosh
Charles Perry
Ray Piercy
Jeff Pogue
Steve Pullins
Henry Quach
Mike Rafferty
William Ranken
Alvin Razon
Caryn Riley

Sebastian Rios
D. Tom Rizy
Tim Rogelstad
Ziolo Roldan
Julio Romero Aguero
Chris Root
Reed Rosandich
Robert Rusch
David Russo
Dan Sabin
Jim Sagen
Bob Saint*
N. D. R. Sarma
Josh Schellenberg
Dave Schepers
Steven Schott
Andy Schwalm
Ken Sedziol
Matt Seeley
Mike Shepherd
David Shibilia
Tom Short
Cheong Siew
Jeff Smith
Rusty Soderberg
John Spare
Joshua Stallings
Lee Taylor
Jay TeSelle
Rao Thallam
Mark Thatcher
Casey Thompson
Betty Tobin
Tom Tobin
S. S. (Mani) Venkata
Joe Viglietta*
Marek Waclawiak
Juli Wagner
Reigh Walling
David Wang
Daniel J. Ward
Cheryl A. Warren*
Neil Weisenfeld
Greg Welch
Lee Welch
Charlie Williams
John Williams
Taui Willis
Mike Worden
Don Yuen
Eena Singh
Andy Holt
Jason Handley
Tony Thomas
Dave Crudele
Bo Van Beekum
Le Xu

*Primary author

The following members of the individual balloting committee voted on this guide. Balloters may have voted for approval, disapproval, or abstention.

William Ackerman
Ali Al Awazi
Wallace Binder
James Bouford
A. James Braun
Gustavo Brunello
Ted Burse
Robert Christman
James Cole
Larry Conrad
Ray Davis
Neal Dowling
Frederic Friend
Michael Garrels
Waymon Goch
Edwin Goodwin
Randall Groves
Donald Hall
Dennis Hansen
David Haynes
Werner Hoelzl
Richard Jackson
Mayank Jain
Laszlo Kadar
Gael Kennedy
Yuri Khersonsky
Morteza Khodaie
Joseph L. Koepfinger
Jim Kulchisky
Saumen Kundu
Greg Luri
Thomas McCarthy
Christian McCollom
John McDaniel
John McDonald
John Miller
Daleep Mohla
Jerry Murphy
Michael Newman
Joe Nims
Lorraine Padden
Richard Paes
Bansi Patel
Christopher Petrola
Craig Preuss
Michael Roberts
Charles Rogers
Bob Saint
Bartien Sayogo
Tony Seegers
Hamid Sharifnia
James Smith
Jerry Smith
John Spare
Gary Stoedter
Lee Taylor
William Taylor
Eric Udren
John Vergis
Jane Verner
Carl Wall
Daniel J. Ward
Val Werner
Kenneth White
Luis Zambrano
Francisc Zavoda

When the IEEE-SA Standards Board approved this guide on 27 March 2014, it had the following membership:

John Kulick, *Chair*
Jon Walter Rosdahl, *Vice Chair*
Richard H. Hulett, *Past Chair*
Konstantinos Karachalios, *Secretary*

Peter Balma
Farooq Bari
Ted Burse
Clint Chaplin
Stephen Dukes
Jean-Philippe Faure
Gary Hoffman
Michael Janezic
Jeffrey Katz

Introduction

This introduction is not part of IEEE Std 1782™-2014, IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events.

This guide was initiated by the desire of members of the working group to be able to have meaningful comparisons of reliability metrics. This guide was assembled to provide information regarding the collection, utilization, and categorization of information related to electric power distribution interruption events for the specific purpose of system reliability comparisons.

The purpose of this guide is to foster uniformity and consistency of collection of data among utilities in the trending and benchmarking of electric power distribution reliability to enable meaningful assessment of the performance of different electric utilities. In addition, this guide is intended to provide education and guidance with the assessment, trending, and benchmarking practices related to electric power distribution system reliability.

There is an industry need, given the widespread attempts to benchmark and compare electric power distribution reliability and the impact of such comparisons on key stakeholders including end-use electricity customers, utility companies, and governmental entities. The guide will describe recommended data collection, utilization, and categorization practices that should be followed to ensure fair and accurate trending and benchmark comparisons.

Contents

IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events

IMPORTANT NOTICE: IEEE Standards documents are not intended to ensure safety, security, health, or environmental protection, or ensure against interference with or from other devices or networks. Implementers of IEEE Standards documents are responsible for determining and complying with all appropriate safety, security, environmental, health, and interference protection practices and all applicable laws and regulations.

This IEEE document is made available for use subject to important notices and legal disclaimers. These notices and disclaimers appear in all publications containing this document and may be found under the heading "Important Notice" or "Important Notices and Disclaimers Concerning IEEE Documents." They can also be obtained on request from IEEE or viewed at http://standards.ieee.org/IPR/disclaimers.html.

1. Overview

1.1 Introduction

Benchmarking of distribution reliability performance has become commonplace in the electric power industry over the past several years despite the fact that useful comparisons are often difficult to make due to the data collection methods employed, differences in system design and operation, and differences in the environments. Many benchmarking studies have been established, each with its own criteria to define how data should be provided and analyzed. In order to arrive at meaningful conclusions, consistent interruption event data and categorization of that data are desirable (Werner et al. [B9]).[1] IEEE Std 1366™ has defined a methodology that, if used, will provide a common way to segment data.[2] The purpose of Interruption Reporting Practices Guide is to define data collection procedures. Clearly this is a large topic; therefore, this guide has been broken into the following three issues:

a) Data consistency and categorization for benchmarking surveys

b) Data collection within the electric power distribution industry

c) Data usage and practices

[1] The numbers in brackets correspond to those of the bibliography in Annex E.
[2] Information on references can be found in Clause 2.

1.2 Scope

This guide provides information regarding the collection, utilization, and categorization of information related to electric power distribution interruption events for the purpose of system reliability comparisons.

1.3 Purpose

The purpose of this guide is to foster uniformity and consistency of collection of data among utilities in the trending and benchmarking of electric power distribution reliability to enable meaningful assessment of the performance of different electric utilities. In addition, this guide is intended to provide education and guidance with the assessment, trending, and benchmarking practices related to electric power distribution system reliability.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 1366™, IEEE Guide for Electric Power Distribution Reliability Indices.[3, 4]

3. Data consistency and categorization for benchmarking surveys

3.1 Overview

This portion of the guide presents suggestions on comparison of utilities based on a high-level categorization of interruption related data. It is not meant to limit how detailed the collection of data could be, or to say what must be collected, rather to define the minimum set of data collection categories required for benchmarking and to give consistency to those categories.

When performing benchmarking studies, the differences between the collection methods, the locations, and the differences in system design can make comparison difficult. Examples of the types of items that may be relevant when performing benchmarking studies are listed below.

3.1.1 Collection methods

A variety of methods available for collecting data, some listed below, could lead to issues when comparing data in benchmarking surveys.

- The differences in the interruption data collection systems (ranging from manually entered paper systems to completely automated computer-based systems)
- The ability to collect interruption data from the system (ranging from the substation level down to the customer service drop)

[3] The IEEE standards or products referred to in this clause are trademarks of The Institute of Electrical and Electronics Engineers, Inc.
[4] IEEE publications are available from The Institute of Electrical and Electronics Engineers (http://standards.ieee.org/).

— The use, or nonuse, of step restoration when collecting interruption data

— The determination of the start time

— The definition of sustained interruption may play a role (ranging from greater than 1 min to greater than 5 min)

— The definition of a customer (acconnt, meter, premise, etc.)

— Interruption delineations (unplanned interruptions, planned interruptions, major events, etc.)

3.1.2 Location

In some cases, a difference in locale could also lead to issues when comparing data in benchmarking surveys.

— System characterization (rural, suburban, urban)

— Climatic information (hot, cold, wet, dry, lightning, etc.)

3.1.3 System design

In addition, the differences in system design could lead to issues when comparing data in benchmarking surveys.

— System layout (radial, loop, two transformer station, etc.)

— System placement (underground or overhead)

This guide includes a minimal set of data and a consistent categorization structure necessary for comparison of distribution system performance. Presented are categories for system characterization, interruption causes, responsible systems, conditions, voltages, devices, device initiation, and restorations.

3.2 Data collected during the interruption event process

As part of the interruption event collection process, the cause is collected with other pertinent information. This information should include:

— The number of customers interrupted (CI)

— The interruption durations, based on start date/time and restore date/time

— The number of customer minutes of interruption (CMI)

As the database is maintained over the years, cause information can be used in combination with the number of interruption events, the number of CI, and the number of CMI to numerous analytical ends, some of which will be discussed in this document.

3.3 System characterization

It is important to identify the composition of the utilities participating in a benchmarking study. The characterizations of the utility system are usually broken into the three categories below. The categories are defined by the customer's density as shown below.

a) Rural (less than 31 customers per circuit kilometer or 50 customers per circuit mile)

b) Suburban (31 through 93 customers per circuit kilometer or 50 through 150 customers per circuit mile)

c) Urban (greater than 93 customers per circuit kilometer or 150 customers per circuit mile)

Percentages of the number of circuits are applied to each of the categories above to describe the make-up of each utility.

As observed in Table 1 below, a simple system composed of the circuits outlined below should be treated as shown below.

Table 1—System characterization example (percent number of circuits)

	Circuit length (km)	**Circuit customers**	**Customers/circuit length (km)**	**Circuit designation**
Circuit A	14	100	7	Rural
Circuit B	50	2000	40	Suburban
Circuit C	12	1500	125	Urban
Circuit D	20	500	25	Rural
Circuit E	27	1000	37	Suburban
[redacted]				
	Urban	Suburban	Rural	
Percent of circuits with system designation	20%	40%	40%	

3.4 Interruption cause categories

Ten general interruption cause categories are suggested for comparison in benchmarking studies. These are intentionally broad categories that will make possible more precise benchmark comparisons between different distribution utilities. There are numerous categories that could be chosen, but with the goal of uniformity for comparison purposes, the following ten categories were chosen:

a) Equipment

b) Lightning

c) Planned

d) Power supply

e) Public

f) Vegetation

g) Weather (other than lightning)

h) Wildlife

i) Unknown

j) Other

The recommended categories do not prevent a utility from collecting more detailed data, and that is indeed encouraged. However, the data collected should able to be placed into one of the ten categories recommended.

The following paragraphs describe the types of interruptions that should be put into each category. Of course, not every possible interruption can be discussed; but for most interruptions, the choice of category is apparent. The cause categories are discussed in the order as presented above.

a) Equipment—Any piece of the distribution system equipment that is defective or fails and causes an interruption to customers should be put in the equipment category. A few examples of equipment types include controls, conductors, insulated transitions, interrupting devices, arresters, structures and supports, switches, and transformers.

b) Lightning—The lightning category includes all interruptions caused by lightning. This may be by a direct stroke contacting the wires or another piece of equipment, or by a lightning-induced flashover of the wires or another piece of equipment.

c) Planned—The planned category includes, but is not limited to: Road construction, maintenance and repairs, load swaps, replacing equipment, and house moves. Typically, planned interruptions are those interruptions that can be delayed by the utility personnel and performed only after the appropriate or required customer notification. Often, regulatory commissions have specified rules describing planned interruptions.

d) Power supply—The power supply category includes interruptions caused by a failure in the transmission system including the transmission portion of a substation or the loss of a generating unit including those associated with distributed generation. It does not include outages due to the loss of a distribution substation component.

e) Public—Any interruptions resulting as an act of the public at large should be put into the public category. Examples include: customer trouble, non-utility employee or contractor dig-in, fire/police requests, foreign contact (such as Mylar balloons, crane boom, and aluminum ladder), traffic accidents, vandalism, and fires and explosions not originating on or within utility-owned equipment.

f) Vegetation—The vegetation category includes interruptions caused by falling trees or limbs, growth of trees, vines, and roots. It should be emphasized that if a tree is involved, the cause category is vegetation. This is important to note during wind storms. It may not be possible to determine that a feeder may have a forestry issue if wind is listed as the cause when actually a tree was involved.

g) Weather—The category of weather should include interruptions due directly to a weather phenomenon including: wind, snow, ice, hail, and rain where the weather itself caused the interruption and exceeded the system's design limits. Wind does not include slapping or galloping conductors; those would go under the equipment category. Ice forming on conductors and tearing them down or flooding of power facilities would be included in the weather category.

NOTE— If any part of a tree is involved, it would go under the vegetation category.[5]

h) Wildlife—This includes mammals, birds, reptiles, and insects, or any other non-human member of the animal kingdom. Wildlife can cause interruptions directly through contact, like snakes, mice, ants, raccoons, squirrels, or birds; or indirectly, like nests and bird excrement.

i) Unknown—The unknown category includes any customer interruptions where a definitive cause cannot be determined after investigation. The level of investigation required is determined by the individual utility.

j) Other—Any interruptions to customers that do not fall into any of the other cause categories should be assigned to the other category. Some examples include: errors in construction, maintenance, operating, or protecting; overload; and contamination.

3.5 Responsible system

When participating in benchmarking studies, it is useful to know the responsible system. This is defined as the portion of the system in which the fault initiated. There are several responsible system categories. These include:

a) Distribution overhead

b) Distribution underground

[5] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

c) Generation

d) Substation

e) Transmission

f) Customer equipment

The customer equipment category refers to customer-owned equipment that is an integral portion of the utility's system, and when a fault occurs on the customer owned equipment, it causes interruptions to one or more of the utility's other customers.

3.6 Conditions

The categories under conditions refer to conditions at the time of the interruption. Many times the condition may be a contributing factor to the number of customer interruptions or the time it takes to restore customers. The conditions may play an important role when analyzing benchmarkiug data. The proposed condition categories include:

a) Routine (day-to-day)

b) Major event

Routine is defined as daily conditions that do not constitute a major event day. A major event day is defined by IEEE Std 1366™ in the major event day definition. These designations would have to be added to the interruption data after the determination that a major event occurred.

Additionally, individual utilities may choose to collect other conditions, such as weather, that were present during the time of the interruption event. For example, each utility could develop a list of weather conditions based upon local climate.

3.7 Voltage level

In some benchmarking studies, information is provided using typical voltage classes (phase-to-phase) as shown in the list below. The voltage information for a customer interruption event should be based on the highest voltage level affected.

a) Secondary/Low voltage

b) 5 kV

c) 15 kV

d) 25 kV

e) 35 kV

f) >35 kV

g) Transmission

3.8 Interrupting devices

Benchmarking studies may review the type of interrupting devices used, their failure rates, how many operations occurred, and the total number of devices deployed. Interrupting device is the device that initiates the start of the customer interruption. The following is the recommended list of categories of interrupting devices.

a) Circuit breaker/substation recloser

b) Fuse

c) Line recloser

d) Sectionalizer

e) Switch

f) Other

The following discussion centers on which particular devices should be put into each category. Of course, not every possible device can be discussed. The circuit breaker/recloser category should include circuit breakers and reclosers found in substations and those used for protection of entire feeders/lines. The fuse category should include line, tap, and transformer fuses. Reclosers located along a circuit/line should be in the line recloser category. Gang switches and blade disconnects are captured in the switch category. Any other interrupting devices not covered by the first five categories, including an open conductor, are grouped under the "other" category.

3.9 Interrupting device initiation

Another analysis of interrupting devices may include the manner in which they operated when they were opened and closed. These operations can fall into the following recommended categories:

a) Automatic

b) Manual

"Automatic" includes all operations without human intervention. "Manual" is any operation that involves personnel to operate the device, whether at the location of the device or from a remote location.

3.10 Customer restoration

Benchmarking studies may analyze how customers are restored after experiencing an interruption to power. There may be several ways to reenergize customers after an interruption. The suggested categories are as follows:

a) Automatic substation transfer

b) Automatic circuit sectionalizing

c) Manual circuit sectionalizing

d) Left disconnected

e) Reenergized at station

f) Repaired defective equipment

g) Replaced defective equipment

h) Replaced fuse

i) Reset transformer breaker

j) Installed temporary

The first category, automatic substation transfer, includes any scheme that transfers customers to an alternate supply in the event that their primary supply is interrupted. This scheme operates without any human intervention. "Automatic circuit sectionalizing" refers to any automatic schemes outside the substation that transfer customers experiencing a power interruption to another energized circuit segment either on the same circuit or a different circuit. "Manual circuit sectionalizing" refers to any action taken by field personnel or remote operation by an operations supervisor to transfer interrupted customers to other feeders/circuits. This also includes resetting midline reclosers and operating switches to reenergize interrupted customers to another part of the same feeder/circuit. In some cases, customers will not be put back in service due to fire, flood, or some other destructive force that destroys the entity requiring power. In this case, "left disconnected" is the category.

Sometimes a feeder/circuit is locked out at the station and no cause is found. The circuit breaker or recloser is closed again (reclosed), and if it holds, the category "reenergized at station" is chosen. It may also be used for transformer or bus outages in the station. The last five categories are self-explanatory.

3.11 Equipment failure or deterioration

Benchmarking studies frequently examine equipment performance as well. This equipment is usually failed equipment that initiated the customer interruption. Typically, pieces of equipment are grouped into different categories. Data collected may be by number of interruption events, number of customers affected, or by duration of the interruption. Results from this data may reveal rates of failure for various types of equipment, if some utilities have a problem with a type of equipment as compared to other utilities, and how the use of equipment varies from one utility to another. The following is the recommended list of categories of equipment.

a) Cable
b) Wire
c) Connector
d) Control
e) Insulated transition
f) Interrupting device
g) Lightning/surge arrester
h) Other equipment
i) Structural support
j) Switch
k) Transformer

The "cable" category includes all cable that is direct buried or placed in pipe or conduit or U guard. "Wire" refers to overhead strung conductors and jumpers. Connections, splices, and other hardware are not included in these two categories. The "connector" category includes connectors, insulinks, splices, etc. The "control" category contains relays, smart meters, and other control equipment. "Insulated transition" is comprised of bushings, insulators, separable connectors, polymeric terminations, potheads, stress relief cones, etc. The "interrupting device" category consists of circuit breakers, reclosers, and fused equipment. The "lightning/surge arrester" and "other" categories are self-explanatory. "Structural support" category includes anchors, poles, towers, cross arms, braces, etc. The "switch" category contains disconnect, isolation, and load break switches; solid-blade cutouts; etc. The last category, "transformer," can inclnde auxiliary, current, distribution, grounding, potential or voltage, power, rectifying, step-down/conversion, and voltage regulating transformers.

4. Data collection within the electric power distribution industry

4.1 Overview

It is generally accepted that in today's operating environment, utilities need to accurately capture information regarding the number of service interruptions, their duration, and the number of customers affected (Robinson et al. [B2]). Most utilities, including investor-owned, municipal, and co-operative utilities, have realized the need to capture equipment outages and the resulting customer interruptions; nearly all capture sustained interruptions. The methods and approaches vary widely depending on the existence and sophistication of installed information systems such as the customer information system (CIS), the geographic information system (GIS), the supervisory control and data acquisition system (SCADA), and the outage management system (OMS). In general, a utility's interruption reporting system uses key information from these systems to improve the completeness and accuracy of reliability information.

Comparing reliability statistics between utilities is a difficult task because of so many factors, not the least of which is differing data collection processes and procedures. During the benchmarking process, it is imperative that consideration be given to the level of data collection and the state of implementation of these systems and their associated processes. Even among utilities that have similar systems, such as an outage management system from a specific vendor, performance differences are likely to occur, due either to customization for an individual utility and/or process differences, and those differences may be significant. Without such consideration, comparison of performance will be inexact.

4.2 Manual collection systems

Typically, a utility with paper maps and little or no connectivity records will utilize a fully manual collection approach. Field personnel estimate the number of customers affected during a service interruption. Utilities couple these estimates with an estimate of the beginning time of the service interruption to determine the impact of each event on customers. This approach may be the least accurate approach of the methods that will be discussed in this guide. It is the one that forms the starting point for most utilities in their evolution to a fully connected system, as most utilities began collecting reliability performance information as a consequence of building a system to assist with quicker power restoration.

The data collected with these systems helps that utility identify and track areas on the systems that have reliability concerns. These concerns could include repeated interruptions and potentially poor customer satisfaction. Generally, the manual reporting system tracks only sustained interruptions and does not record the momentary interruptions. In utilizing this method, step restoration efforts are very difficult to track properly; specifically the customer minutes of interruption are not reduced correctly.

Without a fully connected model that provides the connectivity of each customer to the protective devices upstream on the feeder, utility staff must manually group individual customer calls (tickets) by area and then provide this information to field personnel for restoration. Using this approach may result in customers supplied through different devices being grouped together incorrectly, thereby extending the restoration time. In this case, the field personnel have to contact each customer to make sure everyone is restored with the resolution of the outage. If it is assumed everyone in the area has had service restored, then some customers may need to call back to report their continued interruption.

Typically, the interruption records are manually entered into a spreadsheet, or database, and are maintained as time allows, by available personnel, with varying degrees of timeliness. Most of these systems allow free-form text entry, thereby introducing errors into the system merely from the act of recording the data. Further, the level of detailed information captured for each interruption will be limited and may not always include such information as the cause, the device affected, the location, and a variety of other useful types of information.

With the manual system, the input from field personnel tends to vary greatly in that they are based solely on the individual field worker's best estimate, which can be made as conservative as desired to provide an overly optimistic, or pessimistic, result. Again, the nature of this type of approach provides only general trends and should be used by the utility for internal comparison and not used to benchmark performance with other utilities unless the results are clearly identified as having been generated with a manual system.

4.3 Fully automated outage system

At the other end of the interruption data collection spectrum are systems that utilize a full connectivity model from customers to transformers, to lateral protective devices, to main line protective devices, and finally back to substation protective devices (i.e., breakers) and in some cases even through the substation and into the transmission system. In these advanced systems, the outage management system (OMS) is often based on a complete geographic information system, and in some cases, may include information provided by a real-time substation device outage reporting system via SCADA. With this fully integrated system, the utility has the potential to have an accurate count of the number of customers affected by each outage as well as the dnration of each interruption of service. Beyond installing these systems, utilities must educate employees to ensure that personnel are properly operating all the new systems and understand the impact of their actions. The process is equally as important as the information technology system in obtaining accurate reliability information.

Using such systems allows for the provision of timely resnlts of system performance metrics and performance trending. Analysis may be performed down to specific devices; in some cases to the individual customer level. With the full customer connectivity model, utilities not only will have more accurate information to build their reliability statistics, but they will have the ability to automatically group or combine individual customer calls to specific transformers or fused laterals and thereby minimize the number of tickets or equipment outages being investigated at one time. Once the problem has been resolved and the device restored, all of the customers supplied through this device are considered restored. The connectivity model allows the utility to account for the partial, or step, restoration of portions of the feeder and correctly identifies the duration of interruption experienced by each customer throughout the restoration activities.

Most utilities that have implemented a more accurate and sophisticated connectivity model and outage management system have found that their reliability statistics appear to have deteriorated. In many cases, the new systems enable full accounting of the number of customers affected by each service interruption as well as the service interruption duration because accurate start and end times for the interruptions are captured. Rather than being considered a reason to not implement such a system, the more accurate methods will provide many capabilities for the utility to develop a better picture of problem areas and the comparable magnitude of the problems for prioritization. Furthermore, these systems will help the utility optimize its spending and meet the challenges of ever increasing regulatory and customer scrutiny.

4.4 Implementation of various outage systems

The current technologies, systems, and processes used by different utilities are based on various drivers that are utility-specific and are the result of many years of operation. Until the widespread availability of outage management systems in the 1990s, it was considered adequate to operate based on a manual system. As more public service commissions and customers demanded better data, utilities have requested the development of advanced systems that they could implement. Many of these systems cost millions of dollars and take years to implement. No matter the reason for improvements in the components of the company's outage management process, the utility should build on these advancements to provide improved accuracy and response time.

As a utility considers system enhancements to its mapping, customer information system, facilities tracking, work management, or other related systems, it should consider the added benefits and improvement that can be achieved by building up or integrating these systems with an outage management system/process.

All outage management systems rely on several key components:

— Connectivity model from customer to supply, ranging from:
    1) A link between transformers, devices, and customers
    2) A full and accurate GIS model, including phasing
— Customer interruption reporting from:
    1) Customer service representative contact
    2) Interactive voice recognition unit (IVR)
    3) Web applications supporting interruption reporting
    4) Automated outage reporting device
— SCADA
    1) Substation automation devices
    2) Distribution automation devices
— Automatic meter reading outage reporting
— Outage event report analysis or grouping capabilities, i.e., group by customer, transformer, or protective device
    1) Via hard copy outage tickets
    2) Via electronic database with input:
        i) Via mobile data terminals
        ii) Via manual incident entry

All of the above key components of an outage management system can be provided in many different ways, with varying levels of completeness and accuracy. Most utilities find when they implement more sophisticated models or systems, their reliability statistics worsen due to increased accuracy of data collection.

The need to have accurate maps in electronic format can be a driver for implementing new or improved interruption collection processes. With the implementation of a geographic information system (GIS), the utility can utilize this information to further improve its connectivity model and outage management process. The cost justification for the GIS, and the outage management system, is the ability to utilize the added benefits of these systems working together to improve utility efficiencies and customer service.

On the other hand, for those utilities that do not currently have or cannot justify the purchase and implementation of a GIS, establishment of the connectivity by itself may be justified based on the outage call grouping functionality that can improve the efficiency of the dispatch personnel and reduce outage restoration times.

Gathering the outage information in a timely manner is key. Even the most sophisticated, fully-computerized OMS can only analyze and group the customer interruptions entered into the system. If there is a limit in the number of customer calls that the customer service representatives or IVR systems can enter in a given period, or, the outages calls entered are scattered throughout the territory, the OMS may not reduce the number of tickets or trouble orders for dispatching and tracking. Utilities with limited interruption reporting capabilities may easily be able to cost justify funding for an increased number of customer service representatives, or implement an IVR system.

Further, as utilities improve their connectivity model and outage reporting methods, more emphasis can be made to justify expanding their outage management system capabilities. The OMS can either be developed in-house by the utility or obtained from an OMS provider that can best utilize the utility's existing connectivity model and outage reporting processes. Purchasing a packaged OMS will probably provide the utility with included capabilities that have not been considered in-house but, as a package, can be incorporated into the cost justification for the purchase.

As each utility deals with the key components, it needs to consider the overall importance of each function to the utility and focus funding to any of the components that, if not implemented, will limit the process from meeting the utility's operations and customer reliability requirements.

4.4.1 Evaluating the impact of outage management process changes

Upon implementation of an automated outage management system, indices are likely to change reflective of the differences in measuring outage events. Thus, while index levels may indicate deterioration, this is generally the result of collecting data which was not previously collected or may reflect more accuracy in the collection process. A variety of methods have been implemented to try to measure the effect of the process change. Two specific approaches are discussed below.

4.4.1.1 Before and after OMS comparison results: OMS uplift correlations

An example approach, OMS uplift correlations, is shown below. It can be used for evaluating the impact of outage management reporting "discipline," or an automated outage management system is shown step-by-step below.

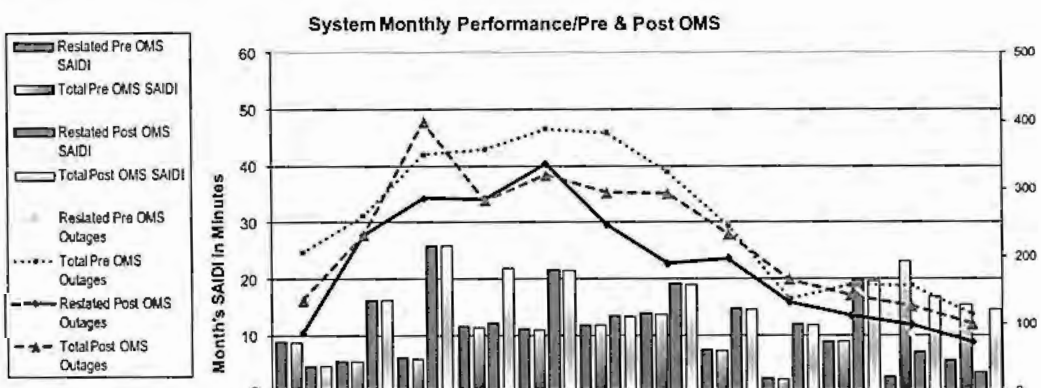
First, the prior system daily performance is assembled. Pre-arranged and customer requested outage causes were removed from the dataset. Next, the post-implementation system daily performance is assembled. Both datasets were reviewed to determine whether any "outlier" events had occurred using the application of the 2.5 beta daily screening (consistent with the method for determining the existence of a major event). For days that reached that level, they were separated out. The remaining days were summarized on a monthly basis, and trouble calls (tc) summarized for the same days and months. Trouble calls were correlated to customer interruptions and customer minutes of interruption, as shown in Table 2. Within Figure 1, visual assessment of the tabular data is depicted, whereby the OMS impact on metrics is visible. This may be considered a form of reporting "uplift." That is to say, while the system fundamentally performed the same, the impact of process results in apparently different performance metrics. In Figure 2, uplift that can be attributed to reporting discipline is shown, as is uplift attributable to network connectivity and outage management system processes.

Several key assumptions exist with this approach. First, it is assumed that there is no substantial change in real reliability before and after implementing these process changes, therefore any known improvements to the system could yield false conclusions, and need to be accounted for. Thus, if implementation occurred at a point in the year where reliability fundamentally alters (i.e., the summer for a summer-stressed system), this assumption would need to be corrected. Second, it assumes that customer trouble reporting processes before and after are materially the same. If any changes to customer call patterns could be expected (which could be due to local news, changes in call handling, changes in call centers or business offices, etc.) this assumption would likewise need to be corrected. Third, an assumption is made that outage duration, both before and after system changes, is also approximately equal. If it is expected that a change will occur (either to lengthen or shorten duration), this needs to be factored into the calculations and correlations.

Table 2—Comparative data for assessing OMS uplift

	Trouble Calls	SAIDI Minutes	SAIFI Events	Sustained Outages	Customer Minutes Interrupted	Restated Trouble Calls	Restated SAIDI Minutes	Restated SAIFI Events	Restated Sustained Outages	Restated Customer Minutes Interrupted
Aug	1 048	12	0.13	382	556 219	1 048	12	0.13	382	556 219
Sep	481	14	0.10	325	647 933	481	14	0.10	325	647 933
Oct	384	7	0.10	245	342 794	384	7	0.10	245	342 794
Nov	267	2	0.03	138	108 734	267	2	0.03	138	108 734
Dec	333	9	0.10	158	417 303	333	9	0.10	158	417 303
Jan	414	23	0.42	157	1082 503	243	3	0.02	86	122 325
Feb	197	16	0.16	115	728 053	148	6	0.05	93	261 612
Mar	224	5	0.08	135	212 855	224	5	0.08	135	212 855
Apr	519	16	0.13	232	904 337	519	16	0.13	232	904 337
May	678	26	0.36	398	1435 332	678	26	0.36	398	1435 332

Correlations Used to Restate	
outages vs saidi post	outages vs tc post
0.75	0.83
SAIDI	
average pre saidi	8.12
average post saidi	15.85
uplift factor	1.95
SAIFI	
average pre saifi	0.10
average post saifi	0.18
uplift factor	1.86



	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Restated Pre OMS SAIDI	8.9	5.4	5.9	11.6	11.1	11.9	13.9	7.4	2.3	9.0	2.6	5.6
Total Pre OMS SAIDI	8.9	5.4	5.9	11.6	11.1	11.9	13.9	7.4	2.3	9.0	23.2	15.6
Restated Post OMS SAIDI	4.6	16.4	26.0	12.4	21.7	13.5	19.1	14.7	12.0	19.7	7.0	3.5
Total Post OMS SAIDI	4.6	16.4	26.0	22.0	21.7	13.5	19.1	14.7	12.0	19.7	17.0	14.7
Restated Pre OMS Outages	206	260	350	358	388	382	325	245	138	158	86	93
Total Pre OMS Outages	206	260	350	358	388	382	325	245	138	158	157	115
Restated Post OMS Outages	87	231	285	284	336	247	189	197	132	112	99	73
Total Post OMS Outages	135	232	398	283	320	294	293	233	166	143	127	100

Figure 1—Monthly comparison of pre- versus post-OMS implementation: monthly SAIDI and outages

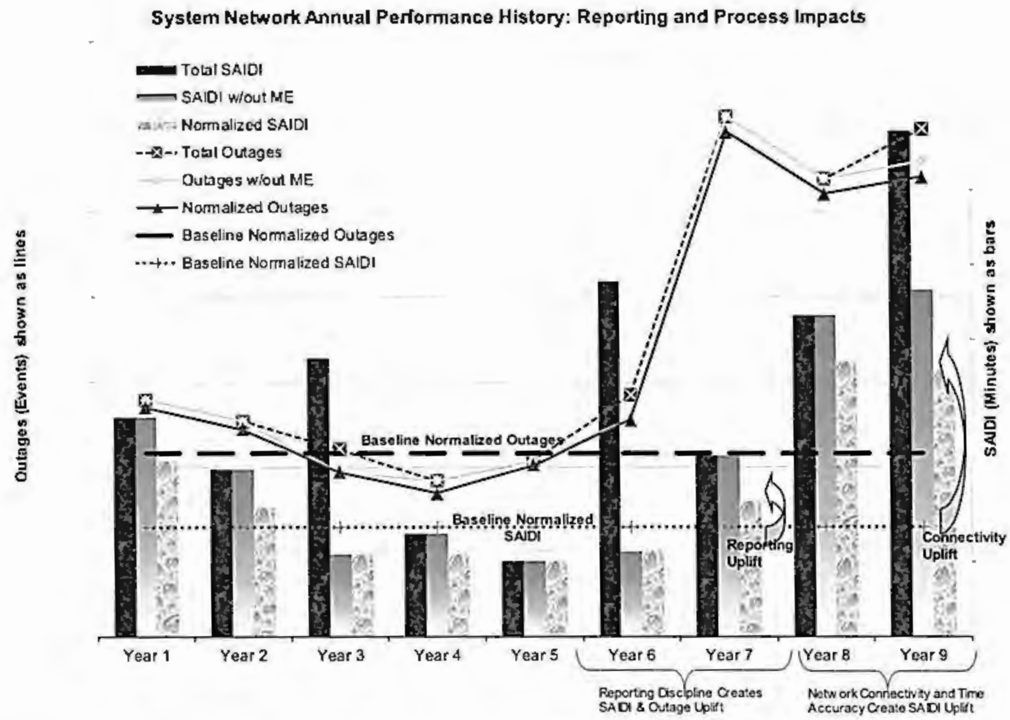


Figure 2—Summary performance history of pre- versus post-uplifted performance: SAIDI and outages

4.4.1.2 Before and after OMS comparison results: "incrementing averages"

Another method of evaluating the impact of system reporting changes, incrementing averages (Bouford and Warren [B1]), is shown in Table 3. It is founded on the premise that incrementing into a historical period, one will be able to discern the tendency of the system, whether it is based on an actual change in performance or on a change in the underlying measurement system. The running average, also called the cumulative moving average, is an unweighted average of the sequence of *i* values $x_1, \ldots, x_i$ up to the current time, and the formula can be written as $Ca_i = (x_1+\ldots+x_i)/i$. The brute force method to calculate this would be to store all of the data and calculate the sum and divide by the number of data points every time a new data point arrived.

To use the method of incrementing averages, the running averages of annual performance are calculated through the period of record by incrementing each start year. This running average calculation is displayed in Figure 3 where there are 11 years, which are then plotted as 11 running averages as shown in Figure 5.

Table 3—Annual performance to calculate incrementing averages uplift method

SAIDI (min)	Running avg	Yr	Yr 11 start incr'd avg	Yr 10 start incr'd avg	Yr 9 start incr'd avg	Yr 8 start incr'd avg	Yr 7 start incr'd avg	Yr 6 start incr'd avg	Yr 5 start incr'd avg	Yr 4 start incr'd avg	Yr 3 start incr'd avg	Yr 2 start incr'd avg	Yr 1 start incr'd avg (same as running avg)
57.6	57.6	1											57.6
56.1	56.9	2										56.1	56.9
73.1	62.3	3									73.1	64.6	62.3
67.8	63.7	4								67.8	70.5	65.7	63.7
60.7	63.1	5							60.7	64.3	67.2	64.4	63.1
41.0	59.4	6						41.0	50.9	56.5	60.7	59.7	59.4
74.3	61.5	7					74.3	57.7	58.7	61.0	63.4	62.2	61.5
67.0	62.2	8				67.0	70.7	60.8	60.8	62.2	64.0	62.9	62.2
79.9	64.2	9			79.9	73.5	73.7	65.6	64.6	65.1	66.3	65.0	64.2
73.1	65.1	10		73.1	76.5	73.3	73.6	67.1	66.0	66.3	67.1	65.9	65.1
92.1	67.5	11	92.1	82.6	81.7	78.0	77.3	71.2	69.7	69.5	69.9	68.5	67.5

A first approach with this data is to look at an average across the entire period using the running average calculations for the first year as shown in Figure 3. The SAIDI for this company appears to be gradually deteriorating; however, no clear conclusions as to the reason can be drawn from this chart. Another way to approach the data is to gradually factor into the analysis more of the years of history as calculated in Table 3 and depicted graphically in Figure 4.

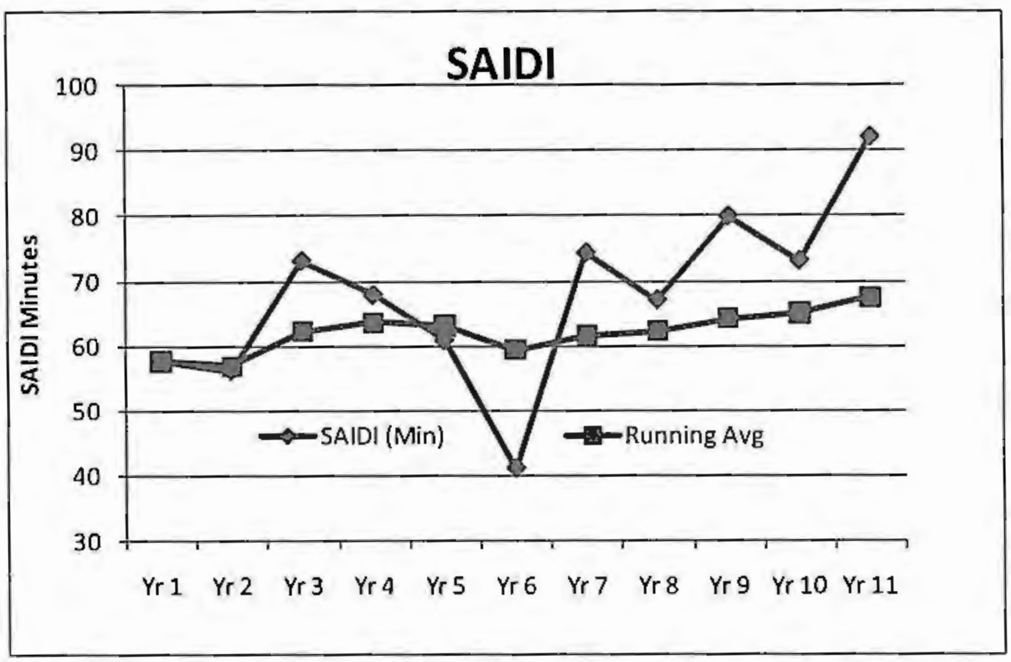


Figure 3—Running average SAIDI

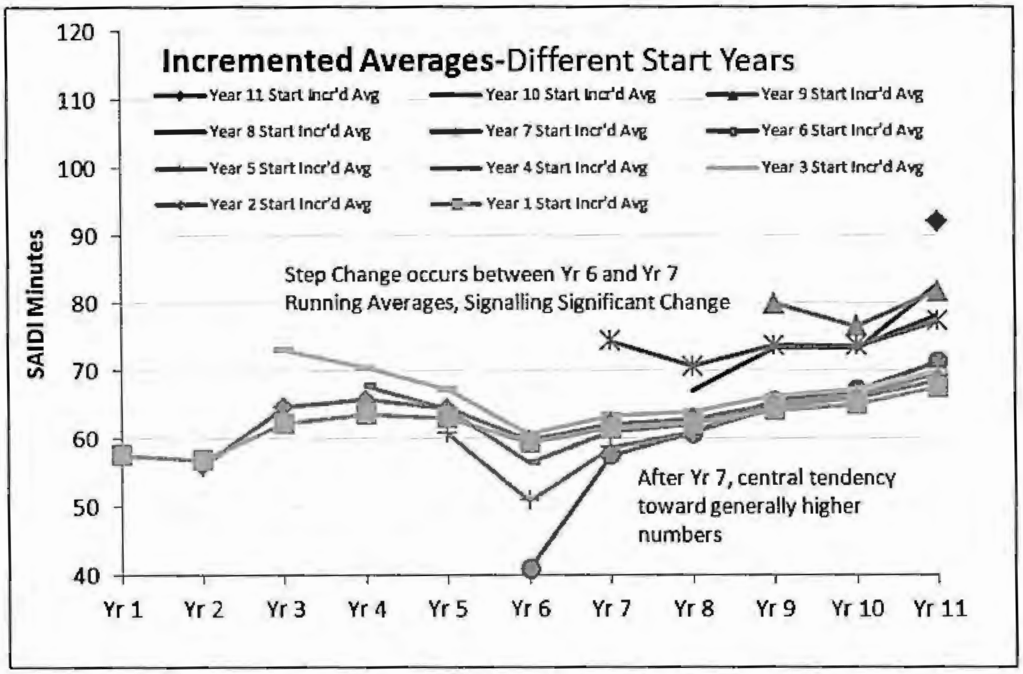


Figure 4—Incremented average SAIDI—different start years

When a substantial step increase occurs in a time series so that the average for the data after the increase is significantly different than that prior to the increase, two distinct groupings will appear when incrementing averages are applied. The magnitude of the increase in the resultant metric value can be determined by the percent difference between the averages of these two groupings of incrementing averages. When the values in the years affected by the introduction of the new data collection system are reduced by the percentage difference of the averages of the two groupings, any other factor affecting the increase will be shown in the plotting of the incrementing averages. The method will also clearly show not only the impact of changed processes/systems but also any system deterioration affects. These may be due in part to weather or other external factors.

Rather than a simple running average, a method of incrementing averages is applied to the data. This is done by incrementing the start year for a series of running averages of the SAIDI values. Figure 5 shows the results for one utility's data set. Each data point on a specific line represents the average from the start year of that line to the year represented by that data point. For example, on the light green line, the first point is the SAIDI for year 3, while the fourth point is the average from year 3 to year 6.

For the years prior to year 7, the incremented averages "track" toward the same value range through year 7, approximately 63 minutes. Even the incrementing averages starting in year 3, year 4, and year 5, which are greatly affected by the outlier value of year 6, trend toward the average of the year 1 through year 6 data set. This can be seen as a grouping of the averages at the year 7 point.

The incremented averages for post-year 6 start years are demonstrating a marked difference in value; they are tracking toward a very different value range than the pre-year 7 values. The post-year 6 averages appear to track toward approximately 78 minutes. For the subject utility, an OMS was implemented in year 7. For many utilities, this will result in a more complete dataset of outage events, more accurate calculations of customer minutes of interruption, and more certainty of the number of customers interrupted in each outage event. What is being shown by this action of the incrementing averages is that the post-year 6 data set has a different, and higher, average value than the pre-year 7 data set. It appears that the introduction of the OMS has caused the SAIDI values to be higher by some rather constant amount. The two distinct data sets have established separate groupings of their incrementing averages for this evaluation period. If the incrementing averages were carried forward for enough years, all the incrementing averages would merge to the average of the complete single data set, but any incremental change that occurs will cause a new grouping to appear. The percent increase of the reliability metrics due to implementing the new OMS system can be determined.

When an incremental change in the average of the data values occurs, a fanning pattern of the incrementing averages, just prior to the change, is seen. This fanning of the incrementing averages is a characteristic of an incremental change in the data set. A constant yearly growth rate, however, creates a different and very distinct pattern with incrementing averages: a series of sloping parallel lines for those years experiencing growth.

The amount of change in metrics due to the introduction of some system change can be determined by the following method. Once the initiation of an incremental change has been determined through the indication of a new grouping of the incrementing averages and the tell-tale fanning of the tracks, the post-change values are reduced by a derived percentage. This percentage is determined by the ratio of the average of the post-change incrementing averages to the average of the pre-change incrementing averages. The average of the pre-change incrementing averages can be found at the location where the tracks with at least five data points are in the year prior to the change. The average of the post-change incrementing averages requires one of two different approaches. If there is a trending of these tracks toward the end point of those with five or more years of data and a general grouping of the tracks exists (other than the effects of obvious outliers), then the average of the post-change incrementing averages will be the average value of those tracks with five or more years of data. The percent change in the reliability metric, due to an incremental change in the process, can now be calculated from the ratio of the post-change average to the pre-change average. The value of this method can be shown graphically by reducing each metric value after the incremental change by the derived percent and plotting the result. Thus, for this example, the factor is calculated by 78 minutes of post-change average performance divided by 63 minutes of pre-change average performance, which results in 1.24, or a reduction of the post-change performance values by 24%, which is shown in Figure 5.

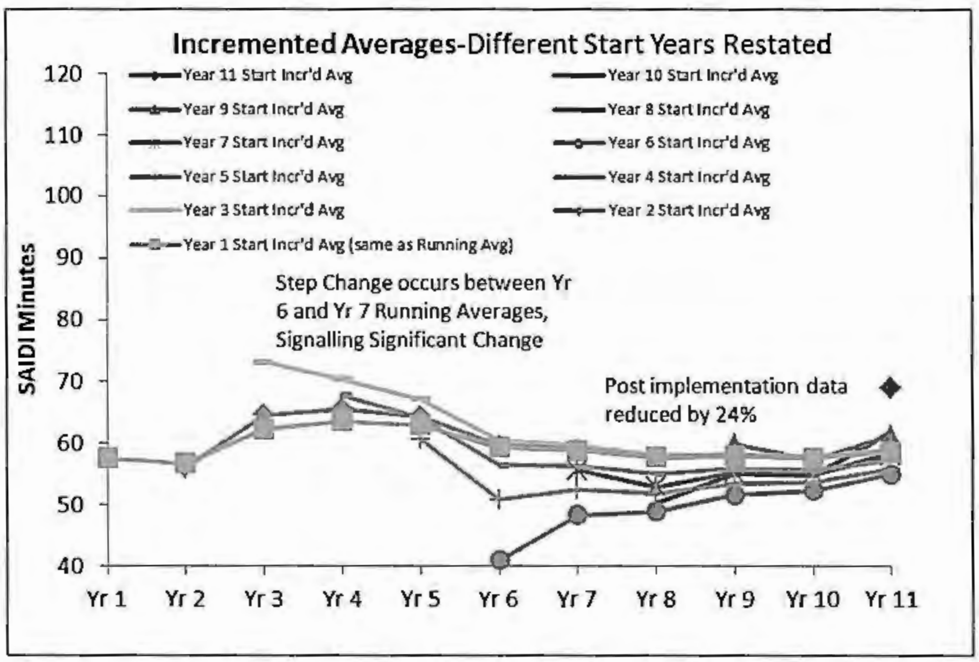


Figure 5—Incremented average SAIDI—different start years restated

The second approach of dealing with finding the average of the post-change incrementing averages is used when the set of incrementing averages includes both an incremental change, noted by the change in the grouping of the tracks, and a constant growth impact, noted by the parallel tracks. The post-change tracks do not trend toward the ending value of those tracks with five or more data points. Therefore, the average of the post-change incrementing averages must be determined by taking the average of the end values of the post-change tracks. The proper way to identify the change in the reliability metrics is to apply both an incremental percent change and a growth rate to the post-change data values. This is done by using heuristic iteration, which involves choosing a reasonable percent increase, subtractiug that impact from the incremental change calculated previously, and viewing the resultant graph of the incrementing averages. One can quickly determine the most appropriate value to nse for the growth rate; it is when the tracks group together and trend to the same data set average value for the pre-change metrics. In Figure 6, both the post-change value and a continuing increase are visible.

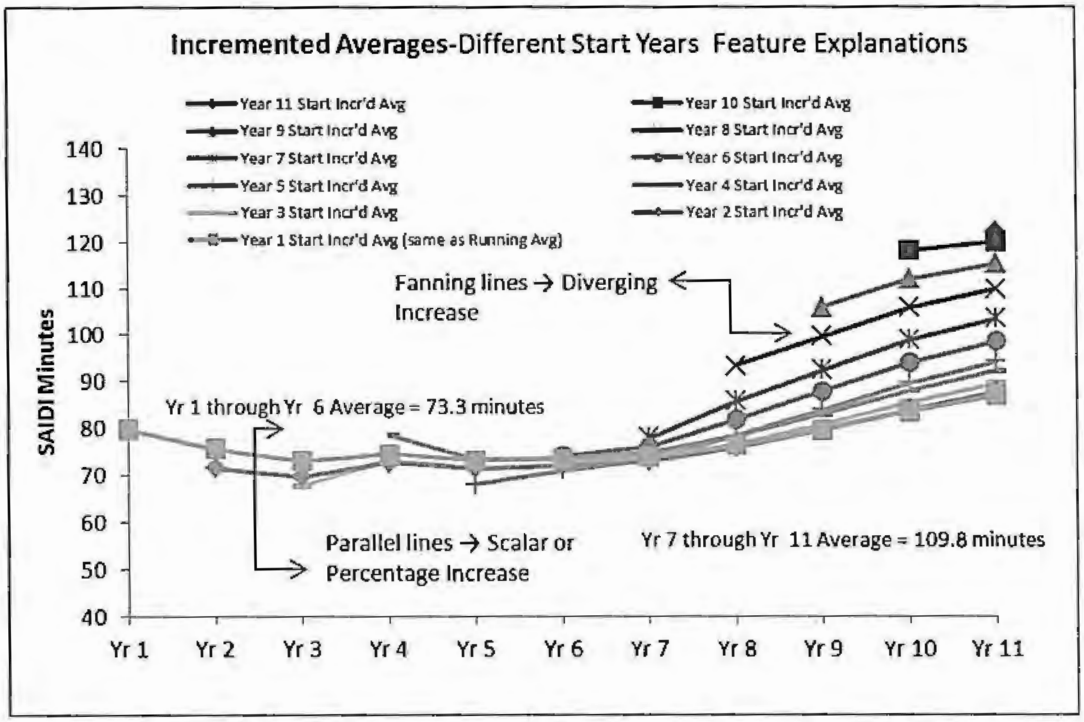


Figure 6—Incremented average SAIDI—different start years feature explanations

When an incremental change in the average of the data values occurs, a fanuing pattern (as shown above in Yr 7 through Yr 11) of the incrementing averages just prior to the change is seen. This fanning of the incrementing averages is a characteristic of an incremental change in the data set. A constant yearly growth rate, however, creates a different and very distinct pattern with incrementing averages, namely a series of sloping parallel lines for those years experiencing growth (as shown above in Yr 1 through Yr 6).

4.5 Interruption records during major events

During major events, the utility must change many of the processes normally followed for interruption reporting during blue sky days. Often during major events, the magnitude of the call volume may overwhelm the OMS or the IVRs or some other key system. This can translate into a challenge to properly and accurately account for the temporary step restoration activities. Another difference during these major events is that many of a company's other systems, such as mobile data terminals (MDTs), have difficulty processing and communicating the massive number of tickets. If the event is large enough, then tickets may have to be manually printed and issued to foreign crews. The timeliness of closing outage tickets even further affects the resulting accuracy or completeness of interruption records. From a benchmarking perspective, these records are usually reported separately if the major event day definition described in IEEE Std 1366™ is used.

4.6 Data validation and auditing

With an increased interest in reliability statistics of utilities by shareholders, customers, and public service commissions, it is imperative that utilities include in their processes validation and auditing of incident records to make sure they are complete and accurate. The review should include correct device and customer(s) affected with the duration of each step of restoration, the cause of the interruptions, the affected equipment, etc.

If a utility has a manual incident reporting process with no customer connectivity model, the level of validation is different than for a utility with a complete customer connectivity model and OMS system; therefore, the type and amount of validation and auditing will vary greatly from company to company. If errors in underlying systems are discovered, processes should be developed to ensure correction. Also, many incident reporting systems have automatic validation at the time of entry to improve the accuracy of the incident records.

The level of validation and auditing of incident records during major events may be different from day-to-day operation due to the amount of information available and the magnitude of the event.

Lastly, state regulatory requirements may impose more extensive validation and auditing to assure accurate and complete records.

4.7 Trending and benchmarking

As long as a utility's interruption reporting system has not changed substantially from year to year, whether it is fully automated or a manual method, the utility should be able to trend its results to identify improvement opportunities.

As noted above, the accuracy of the reliability statistics trend for a utility is very dependent on the accuracy and completeness of the system connectivity model and maturity of the process. Therefore, it is critical when striving to benchmark with other utilities to understand the systems and processes employed by others and to consider comparing only to other utilities with comparable systems and processes.

5. Data usage and practices

5.1 Overview

Each utility expends significant resources to collect equipment outage and customer interruption records. Even though the level of detail captured on each incident or network event varies from utility to utility, the benefits and value achieved by the utility and its customers depends greatly on how the information is used to trend system problems and identify improvements necessary to improve customer service and reliability of supply.

The primary purpose of this section of the guide is to help the user better understand the potential uses of the data in order to determine the level and amount of detail that needs to be captured for each interruption event. Once the desired outcomes or goals have been identified by the utility, the utility can direct the development of its outage management system and its associated incident reporting system aud procedures.

The more in-depth a utility wants to be able to investigate the historical trends to identify key areas to improve or activities that need to be performed on its system, the greater the level of detail of data that must be recorded on each and every equipment outage and customer interruption. Each utility needs to balance the level of record-keeping detail and the extent of diagnostics performed with the additional cost of collecting and recording the pertinent incident information.

This portion of the guide should assist the utility in determining the level of detail desired before a change to the existing system is implemented. There is a relationship between the level of detail of information captured and its value and use. Too few details gathered may mean that not much can be done with the data collected. Conversely, too much time spent gathering details may mean that insufficient benefit is derived for the cost.

A common objective of utilities is to use the data gathered to generate the company's reliability statistics for internal and external purposes. These statistics include, but are not limited to, the company-wide CAIDI, SAIDI, and SAIFI, both for interruption events during normal operations and those associated with major events on the system. The statistics can be developed at the local district or serving office level to allow comparisons from one company area to another. Further, the utility will be able to utilize the statistics to demonstrate to the regulatory authorities that the utility has control of and is managing interruption events via suitable cause code records.

5.2 System indices overview

Reliability trends can be developed using a variety of stratification methods. System indices can be useful in developing an understanding of "normal" system (or sub-system) level performance. A more granular reliability analysis is required to create an understanding of trends for certain geographies, environmental conditions, equipment types, or other stratification criteria.

Some uses in compiling this granular data are shown in the following examples:

Example 1: Annual cumulative daily SAIDI

Indices, such as the daily SAIDI charts shown below, can be revealing in observing days in which a system performs well or poorly; further, it can show changes in system-level performance with time. There are several different ways this data can be presented. First, the data can be shown in a time-dependent fashion, as shown in Figure 7 and Figure 8. The data is prepared by accumulating the daily SAIDI or SAIFI results for a given system (which can be a company, a region, or an operating area), and sorting in date order for a particular period; in this case, an annual basis. No interruption events are removed from the dataset (such as customer requested or pre-arranged). Each pair of colored lines, one dashed and one solid, represents each year's cumulative results. The solid line is after major events have been segregated from the data (ME Excl); the dashed line includes major event day results (total). As can be seen, at year end, the total year results can vary quite substantially, demonstrating the impact major events can have on year-to-year comparisons. In contrast, the ME Excl results are much more consistent, but can still show a trend. For the days that the SAIDI has a stair-step, substantial interruption minutes were accrued on that given day. If the SAIFI chart shows a similar scalar event, it can be assumed that the interruption response was consistent to normal performance in this system. If, however, the SAIFI stair-step is shorter than the SAIDI stair-step on the given day, one could assume an unusually long duration for the day's interruption events. If the SAIFI stair-step is taller than the SAIDI stair-step on the given day, one could assume an unusually short duration for the day's interruption events.

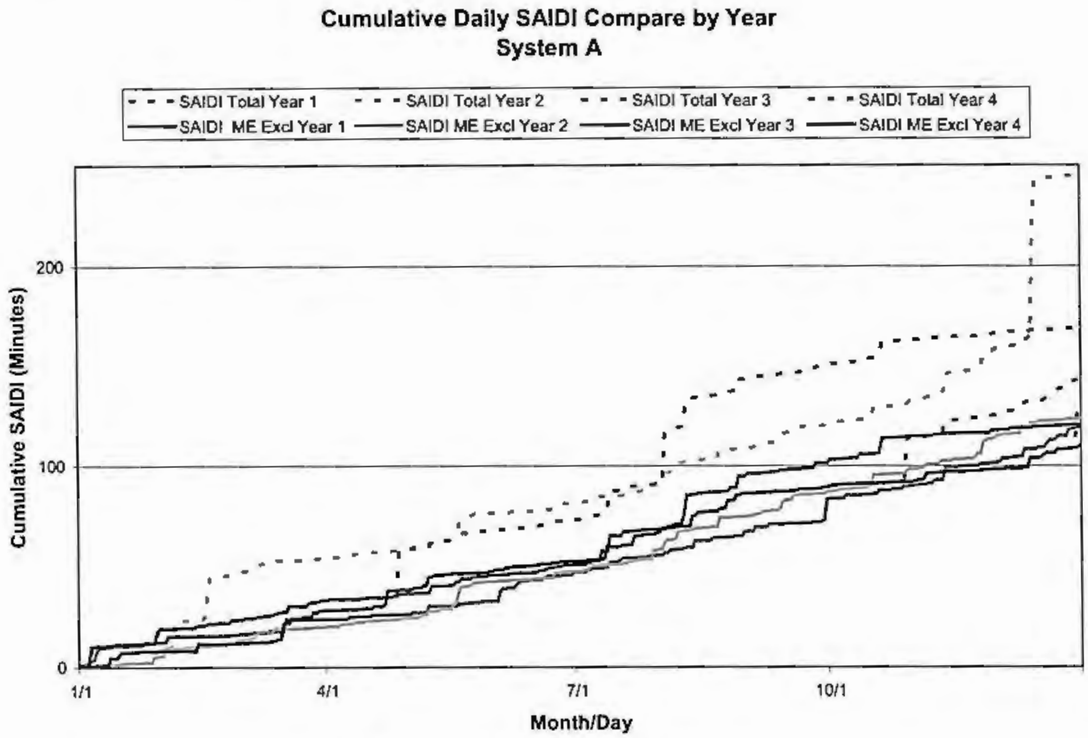


Figure 7—Cumulative daily SAIDI by year

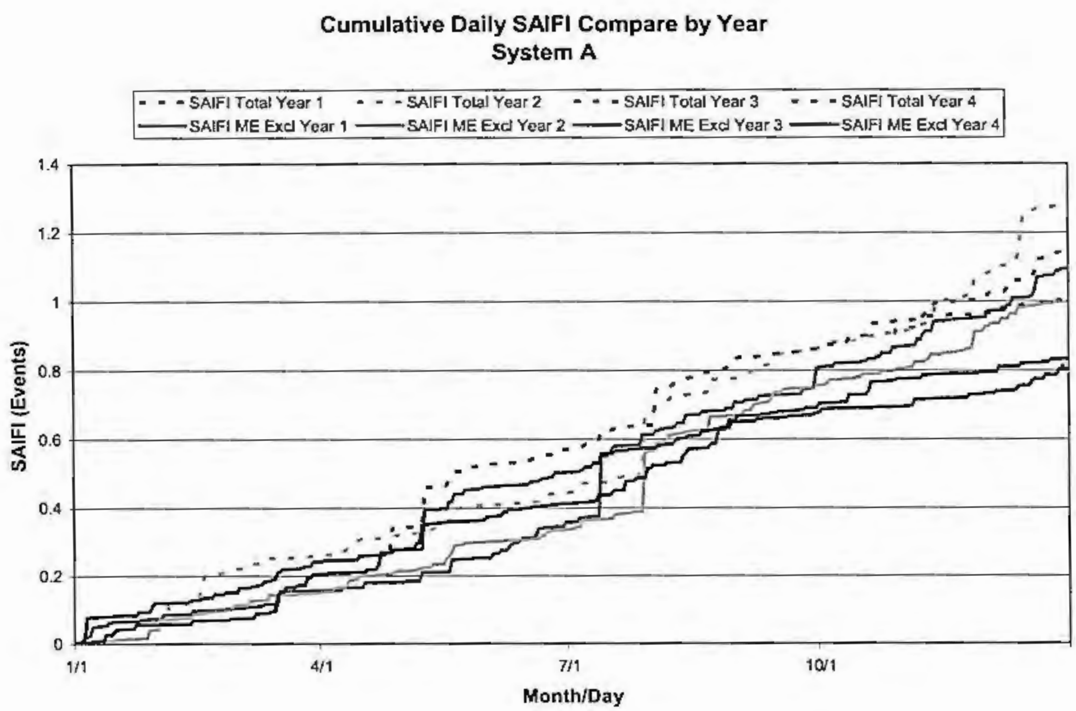


Figure 8—Cumulative daily SAIFI

Next, in Figure 9, the data is prepared by taking the daily SAIDI for a given system (which can be a company, a region, or an operating area) and sorting in descending order for each comparative year with the y-axis represented using a logarithmic scale. No interruption events are removed from the dataset (such as customer requested or pre-arranged). Five years of data for a sample utility are presented. Focus on three key areas for year 5 can show changes occurring with this utility's reliability. The three key areas are 1) the left axis and peaks, 2) the right tail, and 3) the central slope. Assessment of the left axis and peak gives insight into system extreme event performance, and in Figure 9 shows that compared to previous years, the spike is not as significant. The right tail shows more reach of the tail, which suggests more low values, i.e., better SAIDI days, than prior periods. Finally, the central slope for the most recent year shown is elevated (as well as rotated slightly), which suggests poorer daily performance. Further mining into these datasets can continue to provide more information. The chart shown below depicts evidence that large events remain approximately the same; medium events have gotten bigger; small events have gotten smaller.

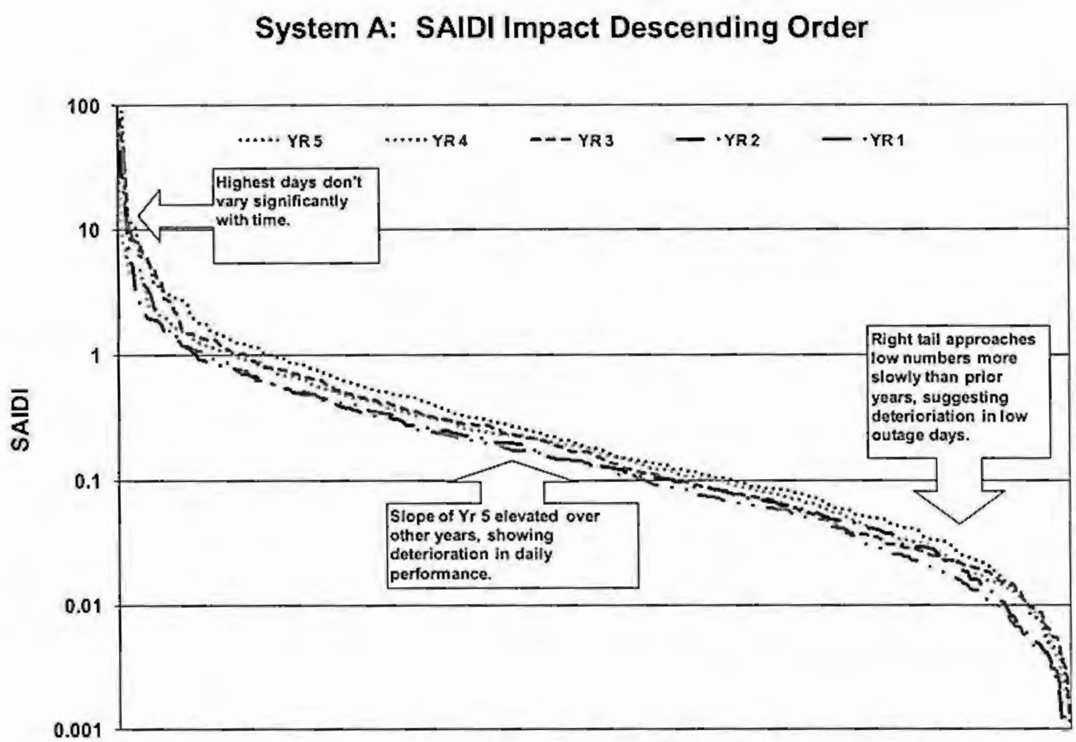
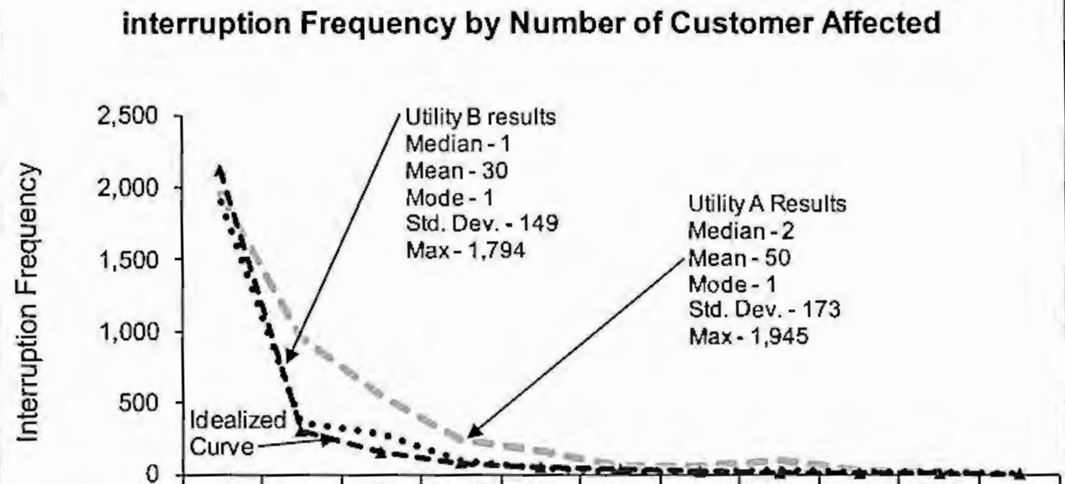


Figure 9—Annual system-wide daily SAIDI, sorted descending order

Example 2: Customers interrupted per interruption event (annual data)

Good design, construction, maintenance, and operation of an electric delivery system will provide an optimum level of reliability for that system's customers. One key principle for good design is an effective system protective scheme, which coordinates properly. Then, when faults occur, the system is able to clear the fault locally and protect the upstream system, affecting as few customers as possible. A "well-tuned" system can be evaluated by analyzing the numbers of customers that are affected by all outage events. Thus, the impact of segmentation (or protective coordination) of the distribution system can be evaluated by the number of customers affected by events. Figure 10 is an example of measuring the effectiveness of this system segmentation. The histograms (or frequency plots) depict numbers of customers affected by an outage versus outages affecting that quantity of customers. Major events, customer requested and planned outages as well as momentary events (less than or equal to five minutes), were excluded from the dataset. The data is prepared by performing a frequency analysis for the system, considering each outage as one record, with the affected customers for that outage. The lower the median, mean, and maximum values are, the better the system has been able to minimize the customers affected by each interruption event, which is directly related to the SAIFI metric. Substantial improvements in system performance can be achieved if the average number of customers affected dnring each outage event can be reduced. Conceptually, the system's frequency of interruptions, or SAIFI, can be calculated by snmming the area under the curve and dividing by the number of customers served by the system. Therefore, the smaller the area (and the tighter it hugs the y and x axes), the lower the system's SAIFI. Utility B's results curve would yield a lower system SAIFI than Utility A's results cnrve. Using this approach, one can conclude whether system coordination (which might inclnde installation of sectionalization) might be beneficial as a means of improving system reliability.



	1	10	50	100	200	300	500	1000	1500	2000	More
Utility A Results	1,951	958	551	236	156	54	57	92	23	13	-
Utility B Results	1,893	367	280	91	39	16	20	23	16	7	-
Idealized Curve	2,117	300	150	80	45	30	16	8	4	2	-

Customers Affected Bins

Figure 10—Interruption frequency vs. customers affected

5.3 Local performance impacts to system reliability to prioritize and select improvement opportunities

As reliability history becomes available, this data can help to inform effective selection of areas for improvement. Clearly, this requires an understanding of what index is being optimized; however, once selected, a variety of opportnnities for improving performance based on historical data may exist. First, if system level duration and frequency are the optimized measures, the facilities that have historically contributed the most to those metrics can be identified and programs targeted. In Fignre 11 through Figure 13, the circuits' impact to the desired metric is prepared, and the circuits that have contributed most snbstantially are identified, sorted in descending order, and displayed. Specifically, for the charts below, customer interruptions and enstomer minutes interrupted per circuit were summed within the system. Each circuit's customer interruptions were divided by the system total customer interruptions and sorted in descending order based on the percentage impact to the system metric. This was duplicated for customer minutes interrupted.

Major events were excluded from consideration in order to remove the volatility that weather can play in changing a circuit's historic performance. Customer requested and planned outages were excluded as well.

Figure 11 shows two different lines charting each circuit's impact to two different systems' SAIFI results. A high impact curve ranks a set of circuits that are labeled as alpha characters, while a line labeled as equal impact curve ranks a set of circuits that are labeled numerically. As you move from left to right, the circuits that impact system SAIFI most prominently are in decreasing order. Thus, the circuits that have the most opportunity for improvement are in ranked order and are at the left-most position. If there is a noticeable point of inflection (or point of diminishing return), as shown in the high impact curve, it is particularly important to evaluate what improvement measures could be delivered to each circuit, such that optimization of cost versus benefit can occur. If however, the curve is close to linear, as shown in the equal impact curve, each circuit has a very similar impact-to-system level SAIFI, and improvements should be selected based on the lowest improvement cost for that circuit. In other words, in the high impact curve example, it is worth refining the selection set. In the equal impact curve example, it is less important to target any given set of circuits, and it is necessary to develop good cost estimates to select improvements.

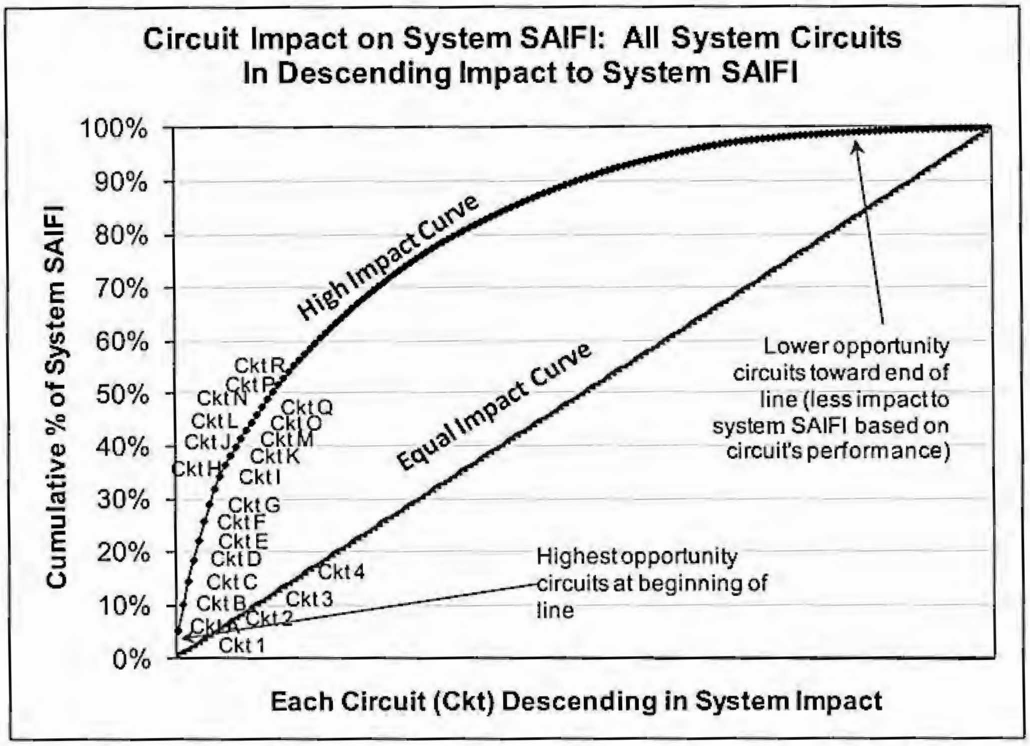
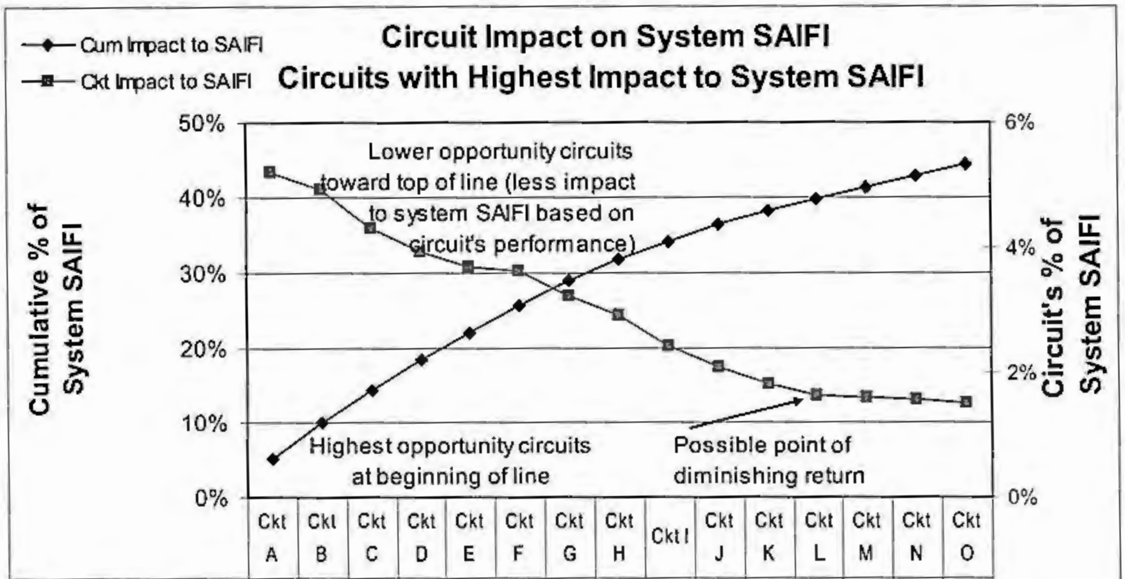


Figure 11—Circuit impact to system SAIFI, descending impact order

Figure 12 shows how the highest impact circuits can be further analyzed to identify historic performance and optimize potential improvement and improvement costs. Figure 13 compares the impact-to-system SAIDI versus system SAIFI using an x-y chart. The richest area for improvement is within the upper right quadrant, since both SAIDI and SAIFI could be improved by targeting those specific circuits. Depending on the techniques to be deployed for improvement, either SAIDI or SAIFI may be chosen as the most critical. Finally, this approach does not take into account the relative cost of each individual circuit's improvement but which is obviously an important subsequent step. When factoring in improvement cost versus benefit, the priority of a given circuit improvement may shift.



	Ckt A	Ckt B	Ckt C	Ckt D	Ckt E	Ckt F	Ckt G	Ckt H	Ckt I	Ckt J	Ckt K	Ckt L	Ckt M	Ckt N	Ckt O
Cum Impact to SAIFI	5.2%	10.1	14.4	18.4	22.1	25.7	28.9	31.8	34.2	36.3	38.1	39.8	41.3	42.9	44.4
Ckt Impact to SAIFI	5.2%	4.9%	4.3%	3.9%	3.7%	3.6%	3.2%	2.9%	2.4%	2.1%	1.8%	1.6%	1.6%	1.6%	1.5%

Each Circuit (Ckt) Descending in Impact (% of System)

Figure 12—Individual and cumulative circuit impact-to-system SAIFI

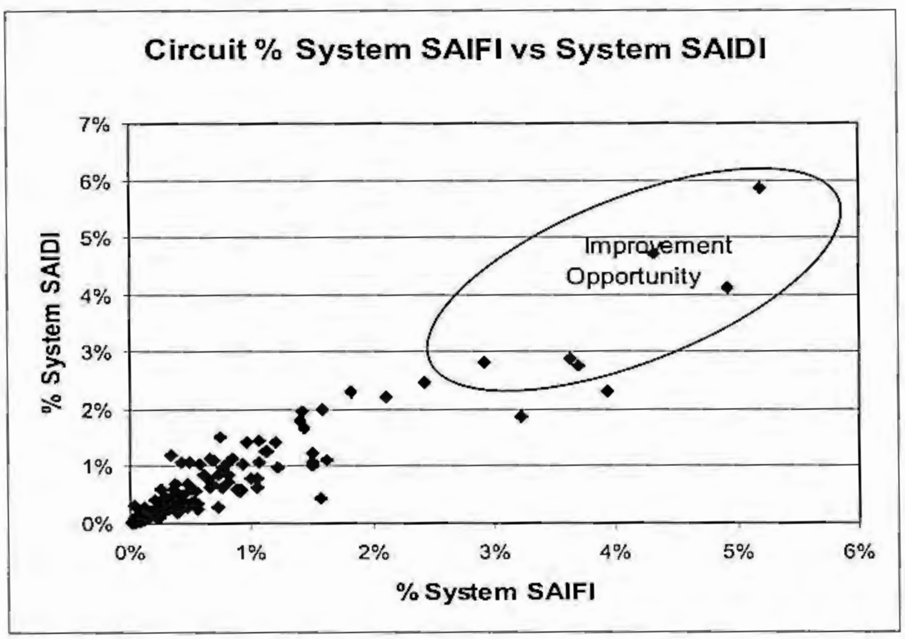


Figure 13—Circuit impact: System SAIFI percentage versus system SAIDI percentage

Many companies, some as directed by their regulators, choose to administer circuit improvement programs. A variety of metrics may be used to determine which circuits might be considered candidates for improvement. In certain cases, metrics (in this case SAIDI, SAIFI, MAIFI, and circuit lockouts) are factored together to identify circuit-level performance over a particular period (3 years has been chosen in this example) to assess long-term trends in the combination of reliability events. For illustrative purposes, one company's equation and coefficients are contained in Equation (1).

$$\text{CPI} = [(\text{Circuit SAIDI} \times W_1 \times E_1) + (\text{Circuit SAIFI} \times W_2 \times E_2) + (\text{Circuit MAIFI} \times W_3 \times E_3) + (\text{LO} \times W_4 \times E_4)] \times \text{Index} \qquad (1)$$

where

W = Weighting factors used to set the degree of importance for each metric (adds to 1.0)

$W_1 = 0.3$
$W_2 = 0.3$
$W_3 = 0.2$
$W_4 = 0.2$

E = Equalizing factors used to put each metric on a consistent scale

$E_1 = 0.03$
$E_2 = 2.4$
$E_3 = 0.7$
$E_4 = 5.3$

Index = 10

NOTE 1—LO = Circuit lockouts (the number of substation circuit lockouts)

NOTE 2—Index = Indexing factor used to magnify the scale for each circuit's score

It should be noted that the choice of emphasis between system reliability and local reliability is likely to lead to selections of different circuits for reliability programs. For example, Figure 11 through Figure 13 show circuits ranked in order of impact to system SAIFI, which is essentially a ranking in order of total customer interruptions, with the system customer count as a constant. In this case, two circuits with 1000 customer interruptions will be counted the same, regardless of the number of customers served by each circuit. Alternatively, the circuit performance indicator equation (CPI) shown in Equation (1) includes circuit SAIFI among its variables. For the CPI, the customer count for the SAIFI calculation is the circuit customer count; a variable. A circuit serving 200 customers with 1000 customer interruptions will have a SAIFI that is ten times higher than a circuit serving 2000 customers with 1000 customer interruptions. Selection criteria that emphasize system reliability tend to favor circuits with high customer counts, while criteria that emphasize circuit-level reliability do not favor large or small circuits. Programs with circuits selected based purely on circuit-level reliability essentially favor improvement in local reliability over improvement in system reliability.

A related issue comes from situations where circuits supply other circuits through large transformers. For example, a 34 kV circuit may serve individual customers through distribution transformers while also serving as the source to one or more 4 kV circuits. An outage on the 34 kV circuit causes interruptions to customers on the 34 kV circuit and the 4 kV circuit(s). Circuit selection criteria could "roll up" the customer interruptions on the 4 kV circuit caused by loss of supply from the 34 kV circuit, or the customer interruptions on the 4 kV circuit may be assigned to the 4 kV circuit regardless of whether the outage occurred on the 4 kV circuit or its 34 kV supply. The first choice, with "rolled up" customer interruptions, tends to support cost-effective programs to control system reliability because circuits with the highest number of customers affected per outage can be identified, and the number of customers seeing improvement for each action taken in maximized. The second choice tends to support local reliability improvement efforts because all service interruptions to customers on a circuit are accrued to that circuit, regardless of whether outages were on the circuit itself or its supply circuit. In this case, reliability programs may have to address the supply circuit as well as the lower-voltage circuit to bring the maximum improvement to the lower-voltage circuit.

It is possible to create CPIs that combine "rolled-up" measures such as total customer interruptions with circuit-level reliability indices such as SAIFI (with customer interruptions not rolled up) to automatically balance the competing priorities of system level and local reliability. The relative priorities are controlled by the weighting factors chosen for the CPI.

With the circuit level approach discussed above, circuits that demonstrate persistently poor performance can be targeted for improvement or pnt on a "watch list." Evaluation of these scores across a system can be used to develop improvement strategies. Figure 14 uses traditional statistics (i.e., a histogram or frequency plot) and shows two different circuit performance distributions. The target distribution of circuit performance is shown in dotted green; fundamentally, the target is to have many circuits with very low CPI scores with a quickly descending count of circuits as the CPI scores increase. At the right end, outliers will exist but should not account for a significant number of circuits. System A closely follows the target distribution, while system B departs heavily from it.

Evaluation of system A suggests there may be some opportunity to slide all circuits toward the y-axis, but generally speaking, the system represents a large number of circuits that perform well with a substantially smaller number of poorly performing circuits shown at the right end of the chart. As shown in the descriptive statistics contained in Table 4, analysis of the medians in combination with the distribution shape can reveal improvement opportunities. For example, system A has a median of 80.2 and circuits that score somewhat higher than that median (worse performance) may be candidates for improvement.

In system B, few circuits hug the y-axis, therefore there is a fairly substantial quantity of circuits at the end of the chart, and there is a central hump of circuits. In system B, there may be ample opportunity for improving performance at a circuit level. Again, targeting above the median may be an effective approach for determining circuits that warrant improvement.

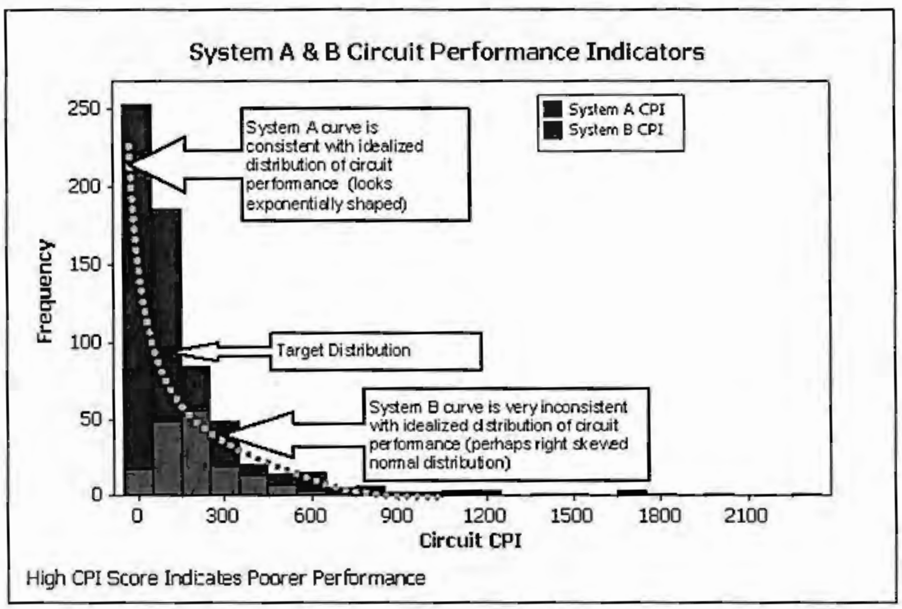


Figure 14—Circuit performance indicators, system A and system B

Table 4—Circuit performance indicators descriptive statistics output (median, mean, and maximum), system A and system B

Descriptive statistics: System A CPI, system B CPI			
Variable	**Mean**	**Median**	**Maximum**
System A CPI	169.6	80.2	2271.3
System B CPI	206.4	190.2	1043.6

This approach can be highly useful to segment a larger system and determine whether each portion of the larger system demonstrates the target distribution. For instance, if a larger system were segmented, perhaps by operating area, county, or some other geographic method, and each operating area demonstrated a distribution consistent to the parent system, there is good indication that no one area is worse off than another. However, if after segmentation, one area reveals a distribution substantially different, it may suggest that the segment demonstrates much poorer or better performance compared to the parent. That level of analysis could form the basis for determining whether reallocation of resources is appropriate.

Example of deliverability factor

Another method that may be considered to prioritize circuit improvements considers the number of customers and the amount of energy delivered over a specified period of time. Using a method such as this may be a transitional method to using other service methods, which are discussed in 3.1.1. In general, circuits with a large number of customers who use a large amount of energy will be weighted more highly for reliability performance. The reliability factor measures the historical performance of the circuit by combining various indices. An example of the deliverability calculation is provided in Table 5, while the reliability calculation is provided in Table 6.

Deliverability factor calculation:

— Determine number of customers on each feeder

— Determine per unit number of customers

(#Customers on feeder/#customers on largest feeder)

— Determine MWH on each feeder

— Determine per unit MWH

(MWH on feeder/MWH on largest feeder)

— Average of pu #cust and pu MWH

Table 5—Deliverability calculation (circuits ranked in descending order of vulnerability)

Circuit	#customers	MWH	Cust PU	MWH PU	Deliverability
Circuit 1	875	36 985	0.51	1.00	0.75
Circuit 2	1728	18 208	1.00	0.49	0.75
Circuit 3	1494	22 403	0.86	0.61	0.74
Circuit 4	1563	17 749	0.90	0.48	0.69
Circuit 5	1227	20 711	0.71	0.56	0.63
Circuit 6	1477	14 191	0.85	0.38	0.62
Circuit 7	1312	17 083	0.76	0.46	0.61
Max	1728	36 985	—	—	—

Once the deliverability has been calculated, they can be divided into groups, say quintiles, after sorting in descending order of deliverability. The 20% of circuits with the highest deliverability are designated "A," those in the lowest 20% are "E."

Example of relative reliability

Now that the relative deliverability has been determined, the relative reliability will be calculated. This example combines the indices of SAIDI, customers experiencing multiple sustained interruption and momentary interruption events index (CEMSMIn) and customers experiencing long interruption durations—single interruption duration (CELID-s). Any combination of indices or even just a single index could be used, depending on a given utility's philosophy or its ability to measure certain indices accurately.

Calculation of reliability factor:

— Calculate reliability indices for period being studied

— Calculate per unit indices value

— Average of per unit SAIDI, CEMSMI5, CELID-s3

Table 6—Reliability calculation (circuits ranked in descending order of reliability)

Circuit	SAIDI	CEMSMI5	CELID-s3	SAIDI PU	CEMSMI5 PU	CELID-s3 PU	Reliability factor
Circuit 1	1015.3	75.7	100.0	0.51	0.76	1.00	0.756
Circuit 2	464.6	68.4	75.0	0.23	0.69	0.75	0.557
Circuit 3	133.6	74.9	50.1	0.07	0.75	0.50	0.441
Circuit 4	693.3	61.0	76.8	0.35	0.61	0.77	0.576
Circuit 5	304.6	39.8	61.3	0.15	0.40	0.61	0.389
Circuit 6	349.8	0.01	50.1	0.17	0.01	0.50	0.230
Circuit 7	2003.7	92.5	80.4	1.00	0.93	0.80	0.912
Maximum	2003.7	99.5	100.0	—	—	—	—

Once the feeders have been sorted from high to low, they can be divided into quintiles. Those 20% with the worst reliability (highest reliability factor) are designated "5." That 20% with the best reliability (lowest reliability factor) are designated "1." The calculation can be done with and without the major event days included.

Now the deliverability factor and the reliability factor are combined. An A5 circuit will deserve the most attention. An E1 circuit will deserve the least attention. In order to combine deliverability with reliability, we will assign "A" feeders a numerical value of 5, "B" circuits a value of 4, and so on to "E" circuits having a value of 1. An A5 circuit has a total value of 10 (most critical), and an E1 circuit has a total value of 2 (least critical). Note that an A4 circuit and a B5 circuit will equal a total value of 9.

A simple example of a table of the 14 circuits for one utility is shown in Table 7.

Table 7—Reliability priority of sample system

Circuit	Deliverability	Reliability MED[a]	Reliability	Reliability rank MED[a]	Reliability rank	Reliability factor MED[a]	Reliability factor	Storm factor
Circuit 1	A	5	5	10	10	0.883	0.756	17%
Circuit 2	A	5	5	10	10	0.539	0.557	29%
Circuit 3	A	5	5	10	10	0.536	0.441	0%
Circuit 4	A	5	5	10	10	0.518	0.576	35%
Circuit 5	A	5	5	10	10	0.517	0.389	0%
Circuit 6	A	5	4	10	9	0.346	0.230	0%
Circuit 7	A	4	5	9	10	0.286	0.355	49%
Circuit 8	B	5	5	9	9	0.937	0.912	24%
Circuit 9	B	5	5	9	9	0.724	0.477	0%
Circuit 10	B	5	5	9	9	0.576	0.517	16%
Circuit 11	B	5	5	9	9	0.511	0.409	6%
Circuit 12	B	5	5	9	9	0.492	0.402	7%
Circuit 13	B	5	5	9	9	0.466	0.376	0%
Circuit 14	B	5	5	9	9	0.439	0.364	1%

[a]Excluding MED.

The reliability factor can be calculated with and without major event day interruptions. Once that is done, a storm factor can be calculated to help determine which circuits might be more prone to "clear day" outages and which are more prone to storm outages. The storm factor (SF) is calculated as shown in Equation (2).

$$SF = ((SAIDI\text{-}SAIDI^*) / SAIDI + (CEMSMI\text{-}CEMSMI^*) / CEMSMI + (CELID\text{-}s\text{-}CELID\text{-}s^*) / CELID\text{-}s) / 3 \quad (2)$$

*Excluding MED.

5.4 Interruption information by cause

5.4.1 Overview

Collecting data on what caused an interruption to a customer, or group of customers, is one of the essentials of a good reliability program. Programs based on cause analysis can reduce the number of interruption events, customer interruptions, and the duration of interruptions. Cause information provides the ability to answer customer questions regarding service reliability and shows trends when analyzed over a number of years. In addition, certain regulatory authorities require the collection of interruptions with associated cause.

5.4.2 Collection and use of data by cause

The determination of the cause of interruption events may lead to preventing the outage from happening in that particular location again due to the same cause. For instance, if a squirrel caused an outage on an overhead distribution transformer, removal of the squirrel and replacing the fuse restores the customers, but adding wildlife protection will prevent another squirrel from causing an outage in the same location again.

Data collection of what caused an interruption also provides the ability to answer a customer's question on why they experienced an interruption to their electrical service. This results in good customer relations and allows the customer to conclude, in some cases, that the cause of the incident was outside the service provider's control. Examples include causes due to contractor dig-ins, traffic accidents, vandalism, extreme weather, and so on. In cases where the cause was due to the service provider, this too can be advantageous by demonstrating to the customer what the problem was, how it was fixed, and what will be done to prevent it from re-occurring.

The example chart shown in Figure 15 gives one possible summary method by cause.

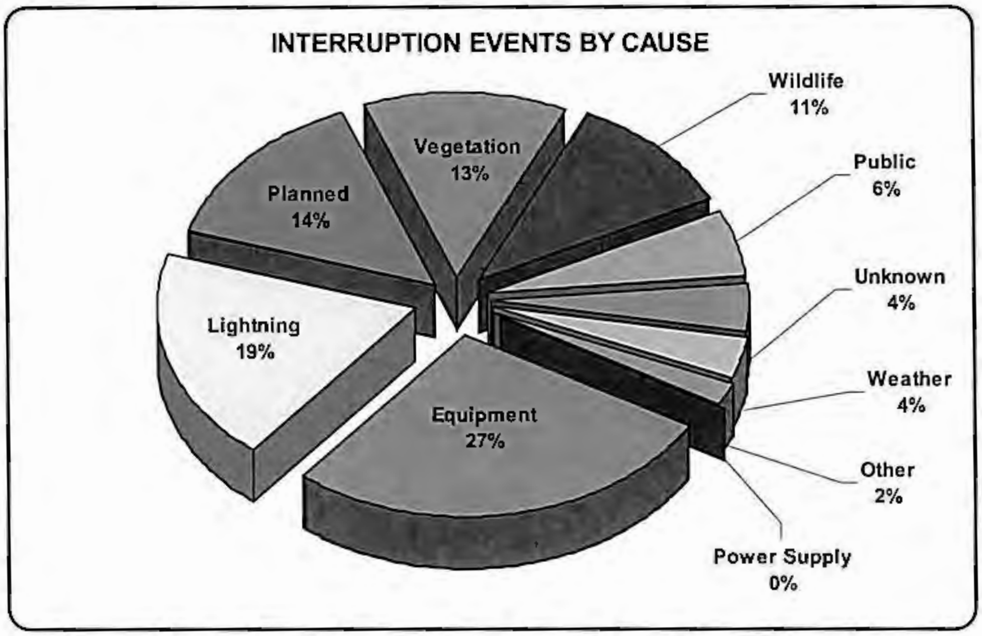


Figure 15—Breakdown of interruption events by cause

As discussed in 3.2, interruption event data should collect key elements of information specific to the interruption. The cause data can be collected to varying extents and is dependent on how broad a definition is used for the causes collected. One service provider might collect a particular cause as equipment (a category); another may break it down further to a function such as interrupting devices (a subcategory); another goes even further to collect the type of interrupting device, for example, midline recloser; yet another might even collect the size, type, manufacturer, and date of installation of the recloser. Every service provider may do it differently. This does not cause a problem as long as the utility is able to:

— Retrieve causal information related to individual events and groups of events.

— Group their causes into the interruption cause categories as presented in 3.4.

— Analyze the data in order to maintain or improve system performance in response to interruption events.

In Annex A, Figure A.1 and Figure A.2 illustrate the use of pie charts to categorize cause by CI and CMI. In addition, a comparison of the number of interruption events by cause over a five year period is shown in Figure A.3. Figure A.4 through Figure A.7 are examples of charts demonstrating the use of the "wildlife" category to separate out the specific kind of wildlife, e.g., squirrel, raccoon, bird, etc. This can be done with each or any of the categories and can be divided into as fine of detail as the utility's needs or collection method permits.

Over time, the data collected by cause can be used to identify trends that can be analyzed at varied levels of detail. This is dependent on the collection method used as discussed in the prior paragraph. Some useful groupings of the data include:

a) Number of interruption events by cause

b) Number of CIs by cause

c) Number of CMIs by cause

d) Causes annually over a period of years

e) Causes monthly over a period of years

f) Causes hourly over a one year period

g) Causes based on the voltage level

Additional examples of charts based on all of the above are shown in Figure A.8 through Figure A.12.

Presenting the data in tables and graphs facilitates identification of specific areas for improvement. The plan or target may be to reduce the number of sustained interruptions, sustained interruption duration, or momentary interruptions. Any of these may be reduced by introducing programs to eliminate or reduce the instances of the cause of the interruptions and resulting reliability metrics. Programs designed to do this, such as a worst performing circuit program, are discussed elsewhere in this document.

5.4.3 Analyzing interruption event trends

While interruption event causes can provide valuable information about reliability trends, segmenting the interruption event cause data in different ways can reveal additional information. For instance, trending by month or day of the year, hour of day, or weather conditions may reveal useful patterns for establishing programs. The analyst needs to ensure that time shifts that could exist within the data have been accounted for, such as daylight savings time adjustments. Further, if service areas span time zones, consideration should be given to translating local time to a consistent time basis, such as GMT. Below are several illustrations of this approach. Figure 16 demonstrates that June through August are months that have high numbers of lightning and tree-caused interruption events for this utility. Also, Figure 17 shows that this same utility experiences peaks in wildlife interruption event causes during spring and fall.

Figure 18 shows how specific hours of the day may peak for various interruption cause events. Animal-caused interruption events occur substantially more often during 8 A.M.-11 A.M., while lightning-caused events occur substantially more often between 4 P.M.-9 P.M.

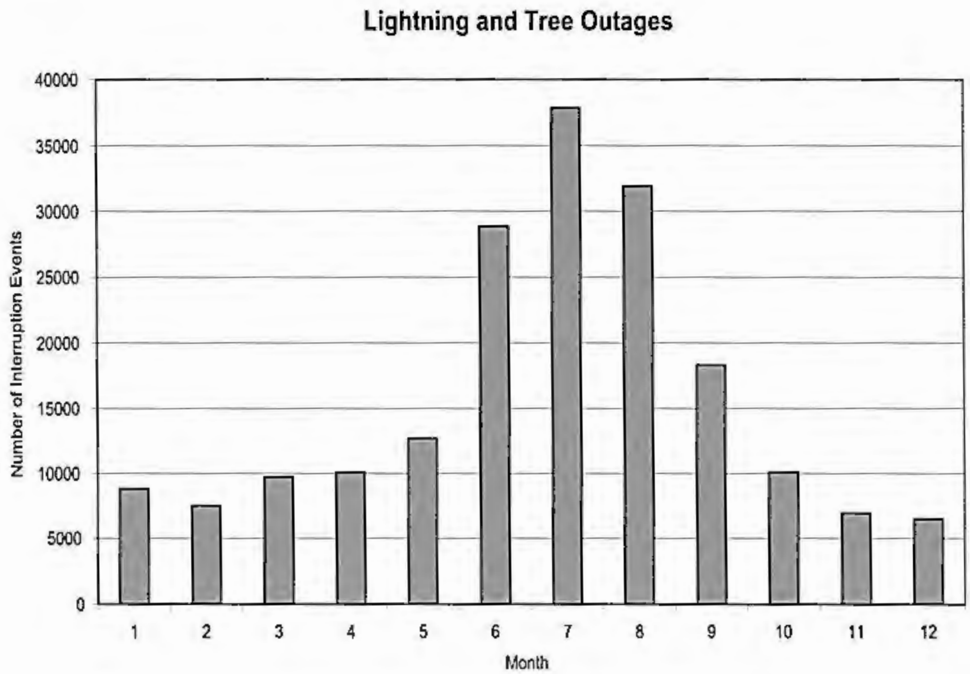


Figure 16—Lightning and tree interruption events by month

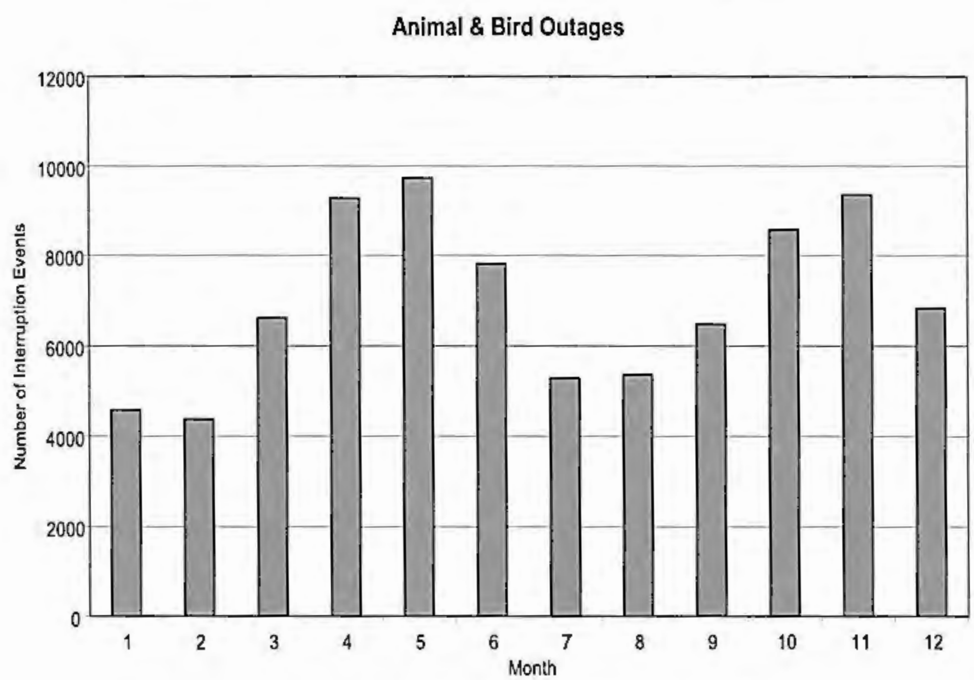


Figure 17—Wildlife interruption events by month

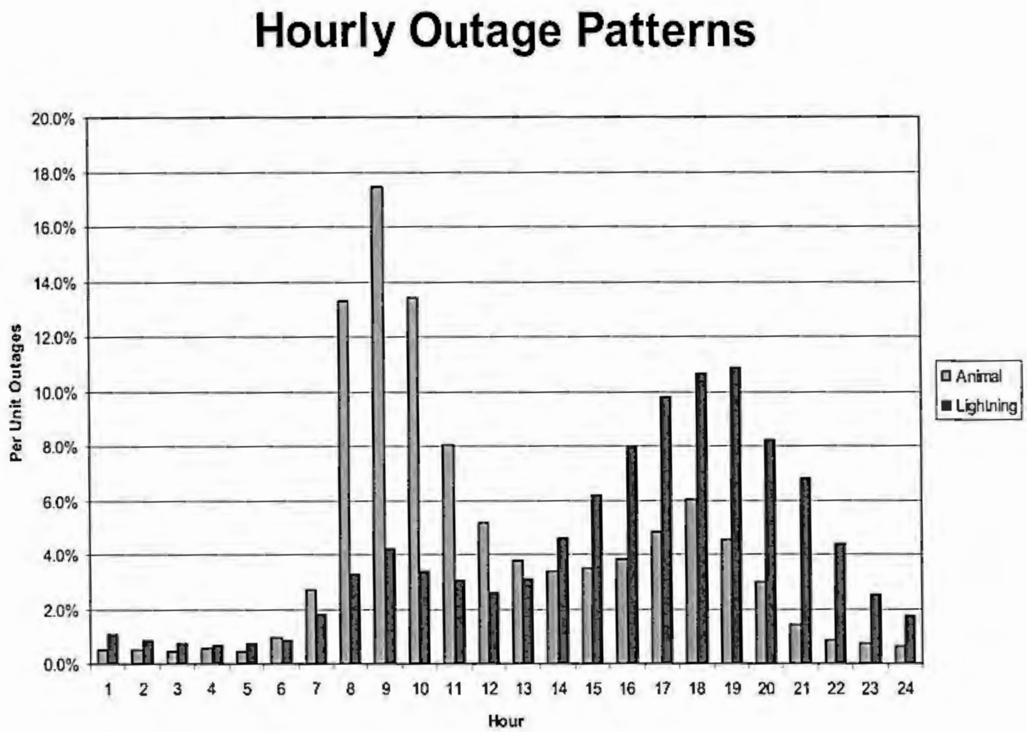


Figure 18—Interruption event by hour

After assessing individual cause code trends, additional analysis can be done for all cause codes as a function of the month of the year, as shown in Figure 19. Furthermore, additional analysis on the devices where the interruption occurred can also be performed based on weather conditions, as shown in Figure 20.

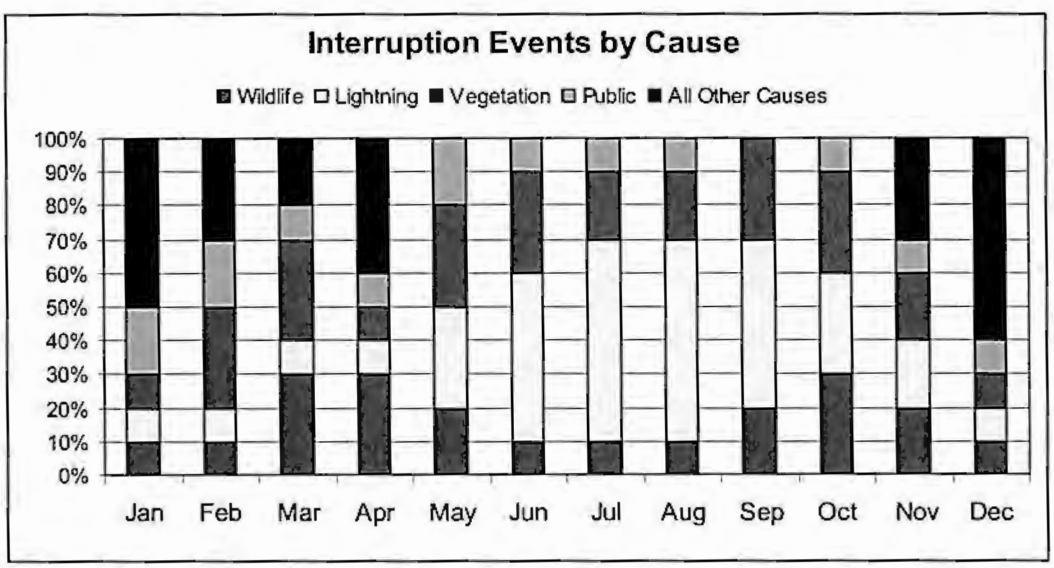


Figure 19—Cause interruption events by month

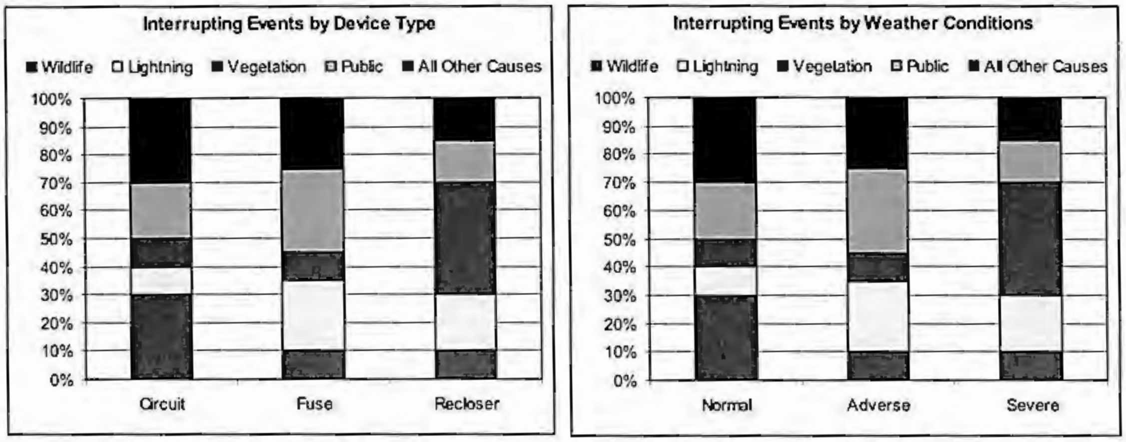


Figure 20—Cause outages by interrupting device and cause outages by weather conditions

5.4.4 Probabilistic analysis of interruption events

Ideally, every effort should be made to identify the actual interruption event cause. In cases where unknown causes or incomplete history exist, companies may develop substantial conclusions about the most likely outage cause based on analysis of historical known interruption event causes. This can be extrapolated to determine the most probable interruption cause. The analytical trends discussed in this section may be used as a method to establish most likely interruption event causes. For example, a company could use time of day, month of year, and type of weather to populate unknown interruption event causes with probable outage cause. After these events have been newly categorized, this output can be used to develop improvement programs targeted toward specific interruption causes.

5.5 Location and device-specific interruption information

5.5.1 Overview

When reliability data began being systematically captured and analyzed, a majority of the information was captured at the circuit level and statistics and metrics developed based on circuits. As information has become more detailed and granular, analytical methods have headed in that direction. As a result, some of the early programs developed by companies may have targeted underperforming circuits; now, more tactical improvements can be done within smaller segments of the circuit, including at the device or the customer level. Below are a variety of segment analyses that can be undertaken.

5.5.2 Customer/service transformer

Most companies have established programs to deal with circuit-related interruption issues based on their interruption databases. More and more companies have been collecting data down to the individual customer or at least to the transformer level. This section explores the use of customer data for reliability tracking and improvements at the customer level. In this implementation, the service transformer serves as a proxy for the customer.

5.5.3 Customers/transformers experiencing multiple interruptions (CEMI) or customers/transformers experiencing multiple sustained and momentary interruptions (CEMSMI)

Some companies have collected substantial information about the impact that repeated customer interruption events, whether sustained, momentary, or during major events, may have on customer satisfaction. Their results have shown that there is a high correlation between customer dissatisfaction and a high number of repeated interruptions. As a result, evaluating the system for areas of high numbers of customer interruptions and taking action to mitigate further interruptions may beneficially impact customer satisfaction. Some companies have chosen to implement $CEMI_n$ programs to set maximum targets for a given period. CEMI can also be used to target general areas for improvement. Many utilities have developed tools to identify and track resolution of these high repeating events to customers. Certain assigned staff review the performance in their area and evaluate pockets of color differentiation for the time period in question, and projects are identified to improve service. The benefit of these programs to the utility is the result of monthly work-plans being generated to target improvements in the areas hardest hit with repeated outages.

Figure 21 shows one company's data for customer interruption frequency (collected at the service transformer). Figure 22 depicts the same information in a plot that uses various colors to denote the number of customer transformer outages rendered in a geospatial way. As shown in the legend, the transformers that have experienced more than six momentary and sustained interruptions are shown in red; those that have experienced five momentary and sustained interruptions are shown in pink; the transformers that have recorded no interruptions are shown in purple. Depending on the distribution of the number of interruption events, the scale can be changed to show sufficient differentiation in the colors since a diagram that has no differentiation gives no appreciation for the parts of the system that have been impacted by outage events.

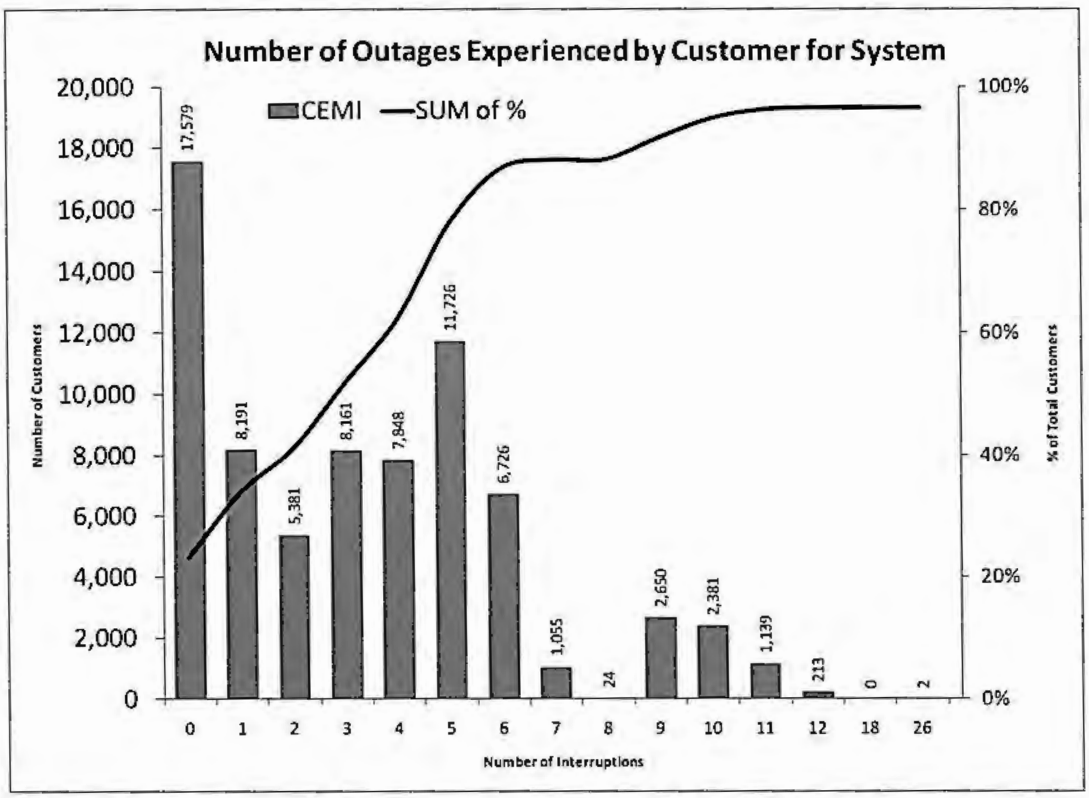


Figure 21—Customers vs. interruptions histogram

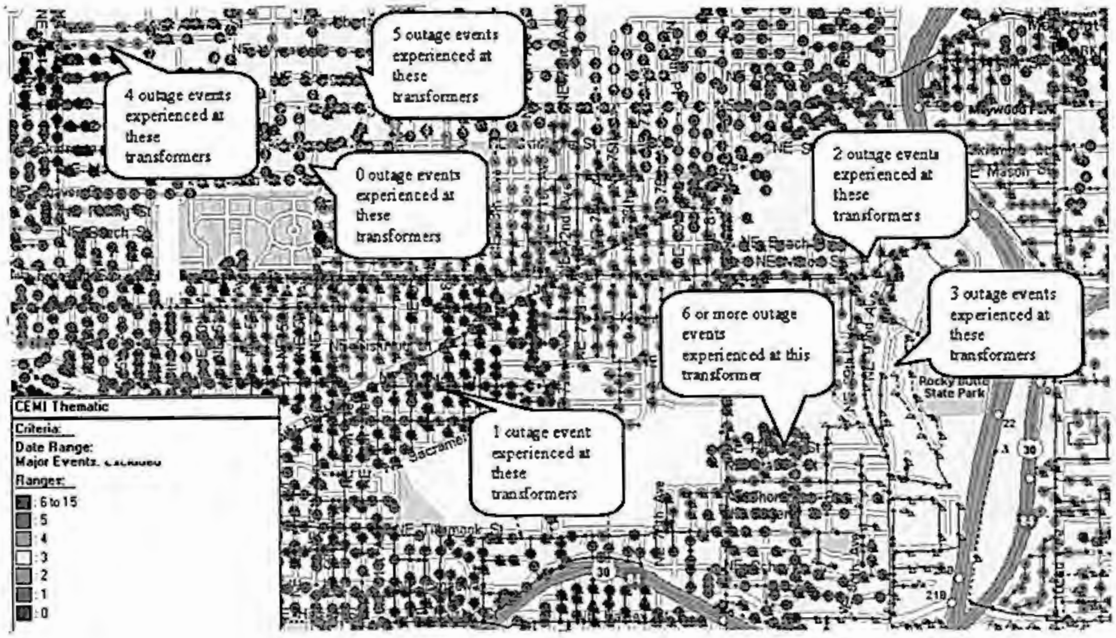


Figure 22—CEMI plot using thematics

5.5.4 Customers/transformers experiencing long interruption durations (CELID-s and CELID-t)

As shown in Figure 23, customer transformer level information can be revealing in showing areas of circuits which may be experiencing localized reliability events that can drive improvements in a more targeted way. This same approach can be taken when evaluating interruption duration at the customer's transformer. Figure 24 shows a similar color-based stratification of performance, with purple showing transformers that have experienced the shortest outage durations and moving up the scale toward red colors shows those customer transformers that have experienced longer total duration. This particular depiction includes minutes interrupted as a result of major events. Therefore, in this example, there may be no reason to take any specific action but to continue to monitor area performance. However, if major events were segmented from the data, perhaps action should be taken with devices showing red or orange colors.

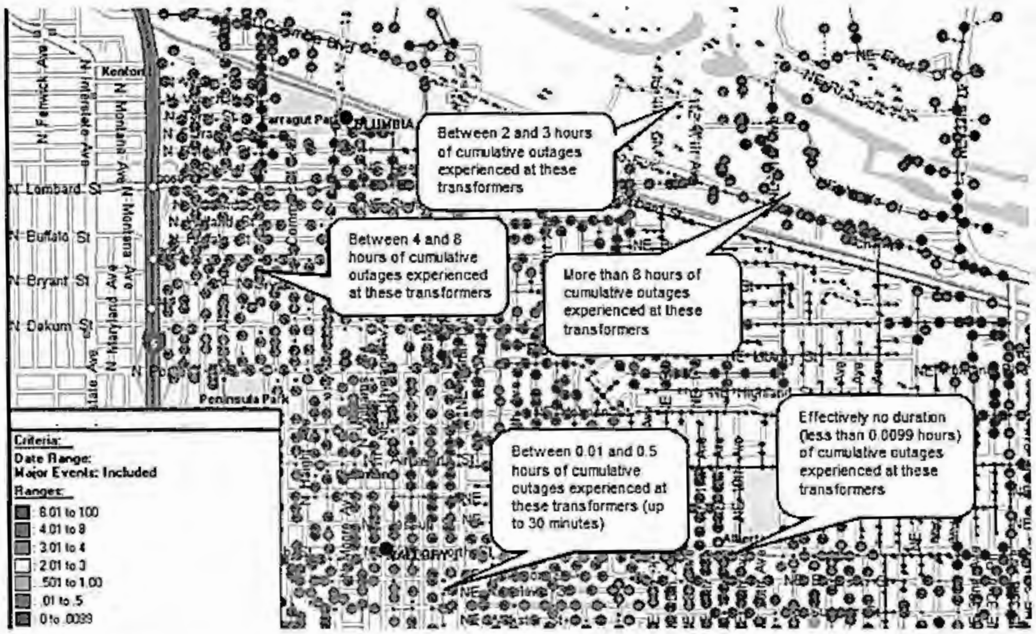


Figure 23—Customers/transformers experiencing long interruption durations, total (CELID-t) using color thematics

Another geospatial depiction of customer transformer reliability is shown in Figure 24, where interruption durations exceeding key values are shown. In this way, long duration events can be evaluated to determine whether a part of the system has experienced events exceeding particular key values.

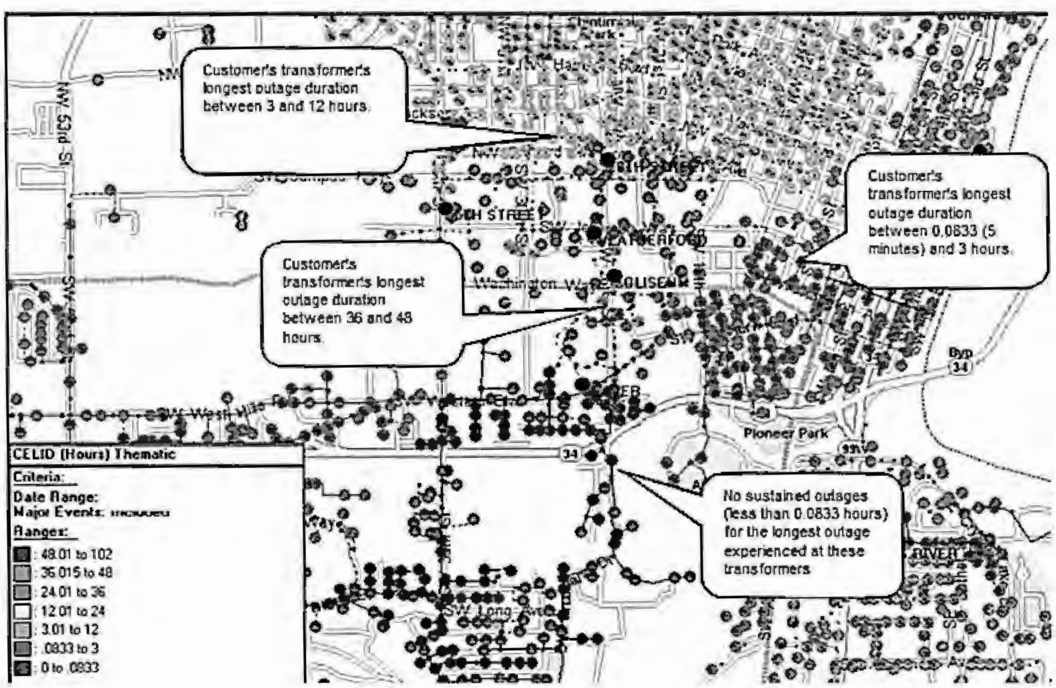


Figure 24—Customers/transformers experiencing long interruption duration, single (CELID-s) using color thematics

5.5.5 Device experiencing multiple interruptions

In some cases, interrupting devices such as circuit breakers, reclosers, or fuses operate repeatedly due to issues downstream of these devices. Reviewing device operations greater than a single transformer interruption can also reveal interesting patterns contributing to system reliability. In general, it is important to evaluate performance, consider the types of devices, and determine expected performance patterns to compare to actual history. With this data, specific analysis of the devices experiencing operations beyond threshold limits can be performed and improvements designed and implemented.

5.5.6 Circuit breaker interruptions

Typically, circuit breakers (or station reclosers) have a large impact on customer interruptions and system reliability. Routine review of such operational data can lead to reliability improvement activities. Figure 25 shows an example which reveals, at a substation and breaker level for a particular period, the number of momentary and sustained interruption events the device has experienced. Analysis of this data can be helpful in determining:

a) Whether device settings or coordination are appropriate

b) If circuit patrolling or hardening may be beneficial

c) Other circuit modifications that might reasonably be expected to impact reliability

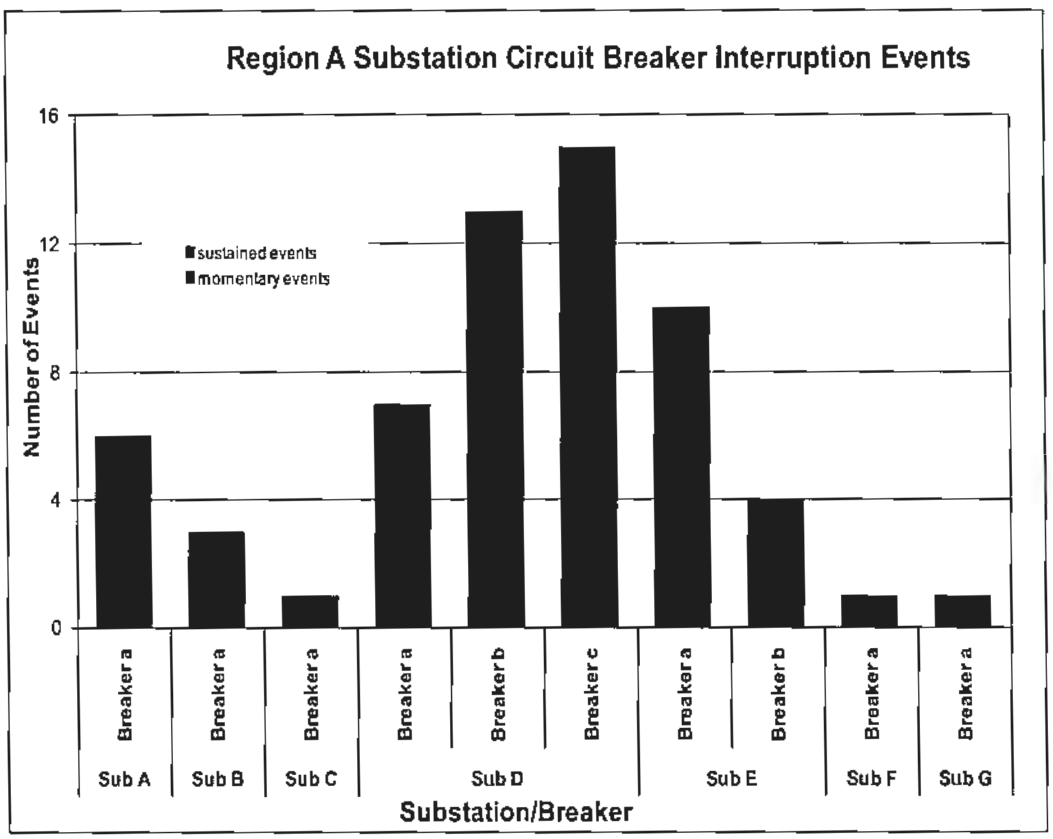


Figure 25—Circuit breaker momentary and sustained events

5.5.7 Downstream device interruptions

After circuit breakers have been analyzed and downstream devices (such as reclosers, fuses, etc.) have been reviewed, interruptions can provide additional clarity of reliability problem areas. Figure 26 is a geospatial depiction of device interruptions with colors denoting devices that have operated 0 (purple), 1 (blue), 2 (green), 3 (yellow), 4 (orange), 5 (pink) or 6 or more (red) times during a particular period. Thus, the device shown in Figure 27 that has operated more than five times in the center of the plot warrants further review (as do several other locations). Device operations should be reviewed for the appropriate or proper operation. High counts could show a problematic device, a troublesome line segment, or a difficult location, which may warrant remediation.

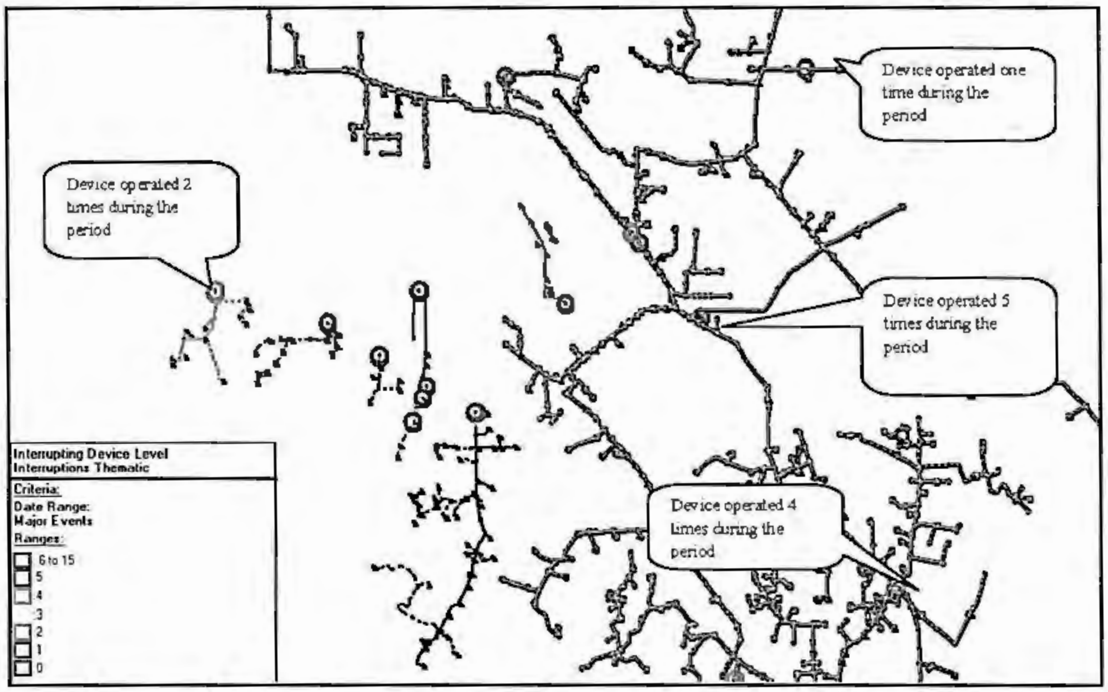


Figure 26—Geospatial device operations by number of interruptions

5.5.8 Interrupting device placement

Another representation, shown in Figure 27, is a depiction of the distribution of a circuit's interrupting devices. Each color change identifies an additional interrupting device. Evaluating the circuit topology can help to identify large segments or tap lines that may not have interrupting devices; comparing this view against customer/transformer level outage data as discussed in 5.5.2 will highlight areas that may benefit from additional interrupting device placement.

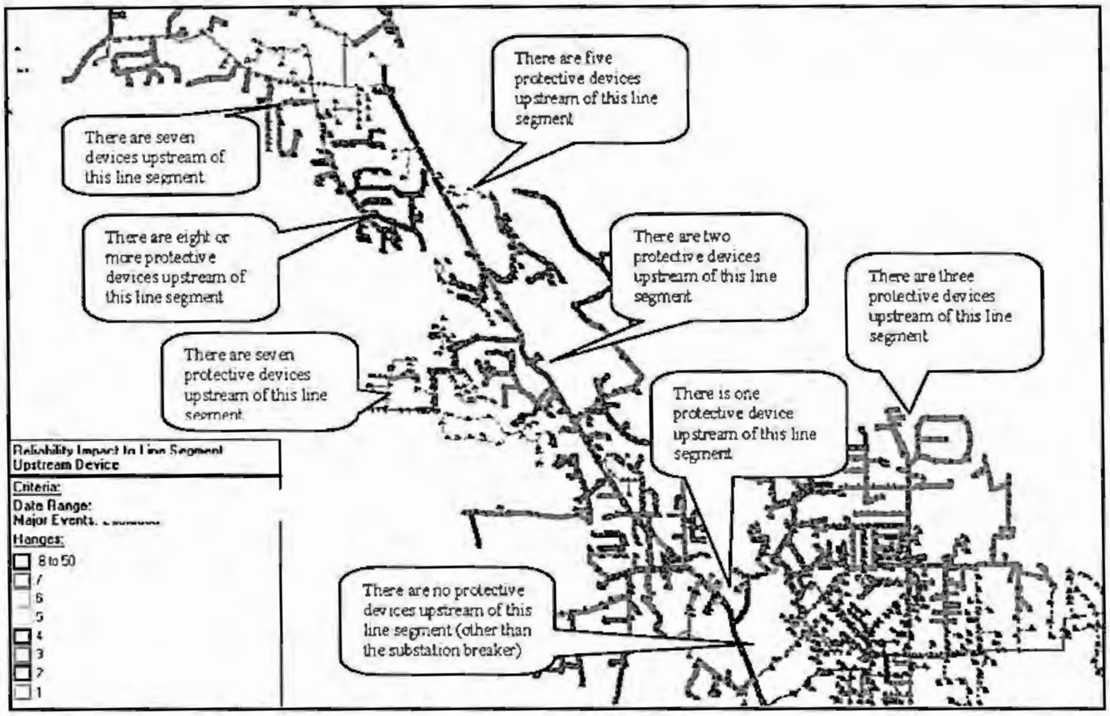


Figure 27 —Geospatial interrupting devices along the circuit

5.5.9 Line segments

When targeting areas to improve reliability, another way to tactically address pockets with reliability concerns is to evaluate line segments that have contributed substantially to circuit SAIDI or SAIFI. Figure 28 shows segments that have high line segment SAIFI based on calculations of interruption events that occurred within the segment divided by the number of connected or downstream customers. This particular approach nses all interruption events within and downstream of the section. Certain utilities may be able to diagnose on which particular line segment any fanlt events may have occurred, while others are limited to identifying only somewhere on the line segments downstream of the interrupting device which operated during an outage event.

In Figure 28, black indicates areas that have seen essentially no line segment SAIFI, while the light blue indicates a small amount of SAIFI. In contrast, red, then dark orange, then light orange have contributed the most (from most to least, respectively). Using this thematic coloring, strategic device or segment investigation can be undertaken. Ideally, as one traces from the far reaches of the circuit upstream toward the substation, the coloring would change from black to blue to green to yellow to red. If a red segment exists in the interior or at the far reaches of the circuit, it could imply that segment has experienced an inordinate amount of interruptions, yielding the higher line segment SAIFI. These areas can be analyzed further to determine if additional circuit protection or hardening might be warranted. In this way, for longer or larger circuits, targeted improvement activities can be undertaken. However, if very few customers are downstream from a reddish line, that may not necessitate any specific action, whereas those that have substantial numbers of cnstomers downstream might benefit by prompt action.

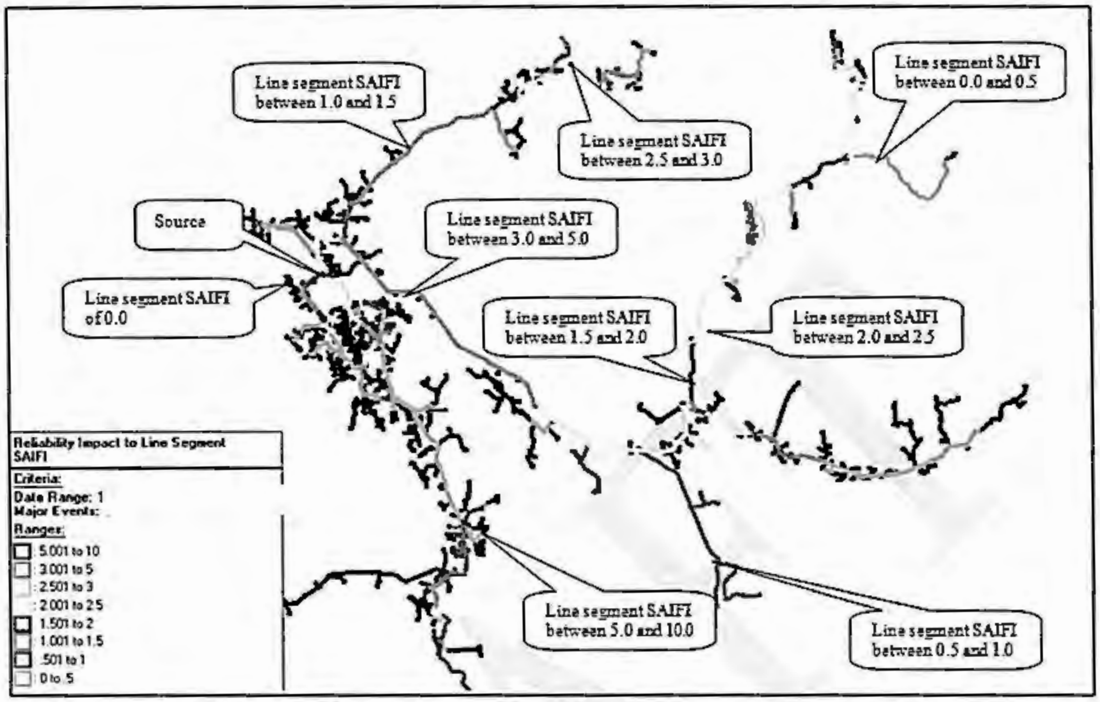


Figure 28—Geospatial impact to circuit-level metrics (SAIFI)

5.5.10 Interruption information by responsible system classifications

Impacts by different portions of the power system can be analyzed to determine which portions are contributing most significantly to system reliability. Figure 29 displays the percentage of customers interrupted due to different responsible system classes; 3.5 details further how interruptions may be classified using this approach. It indicates that, for the subject utility, the majority of customer interruptions are due to the distribution overhead system.

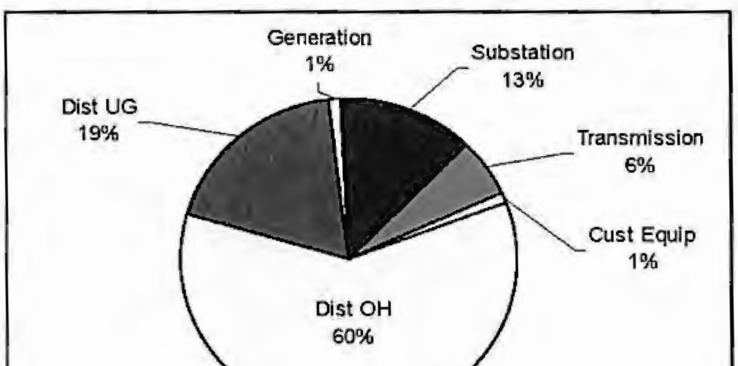


Figure 29—Breakdown of customer interruptions by responsible system

Comparing the customer minutes interrupted pie chart in Figure 30 to the customers interrupted in Figure 29 shows that a larger proportion of customer minutes is a result of distribution overhead interruption events, while the distribution underground is smaller; i.e., 42% of the customer minutes are a result of distribution underground while only 19% of the customer interruptions are the result of distribution underground. Analysis of this kind may reveal opportunities for improving systems with a goal toward outage response or CAIDI improvement.

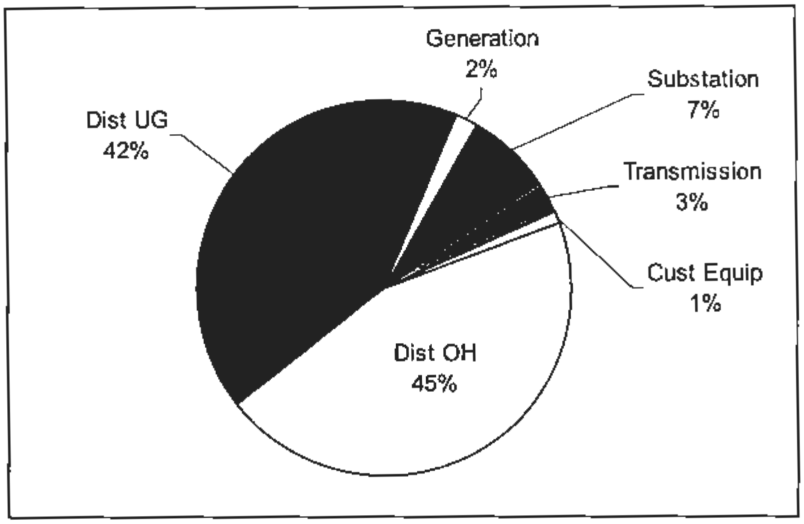


Figure 30—Breakdown of customer minutes of interruptions by responsible system

5.5.11 Breakdown by voltage class

Presentation of reliability results by primary voltage level can provide valuable insight as to the actual problems affecting reliability in a system. Lower voltage circuits typically are shorter, serve fewer customers per circuit, and have less voltage gradient stress to cause flashover due to inadvertent contact or insulation breakdown. One could expect a direct correlation of reliability performance to primary voltage level. Higher voltage designs require greater attention paid to the construction details to off-set their tendency to more easily flashover or breakdown insulation. The ability to segregate the reliability data by voltage classes, or levels, can prove useful. Being able to monitor the reliability trends, and target improvement programs for those that have instituted a voltage upgrade policy, or that have acquired differing systems with numerous primary voltages, can provide information to focus the attention on monitoring more closely, increasing maintenance, or upgrading the existing system. In addition, pockets of problem areas within each identified primary voltage can be found that might be masked by the overall system metrics. See Figure A.11 in Annex A for examples of voltage charts.

Further breakdown within voltage classes by other categories identified within this document, such as system construction or causes, can be performed to identify specific areas of improvement.

5.5.12 Breakdown by system construction

When utilities have the ability to analyze the impact of their different construction types and styles and the resulting reliability performance, the utility can review and modify its construction standards if necessary to the overall best performing configuration. In order to do this, interruption records must consistently include information on the construction type at the location of the interruption.

5.5.13 Interruption information by geographic/geopolitical boundaries

It is often important to be able to show reliability information for political areas such as state or county, or by other geographic boundaries such as company operating region. Examples in this subclause provide information on using trends of customer interruptions, expressed as SAIFI, with respect to geographic considerations. Figure 31 represents the SAIFI for customer interruptions in four different systems (in this case, state) during Year 1 through Year 7. The data is represented for the entire system and does not include the major event day customer interruptions. As can be seen, there are no obvious patterns from system to system; nor is there a common trend upward or downward. In general, it could be concluded that System C is showing a steady upward trend that has generally been corrected, while System B has remained approximately flat, and System A and System D show a common trend in a generally upward direction. Additionally, at Year 1 there is no significant variation in system performance among all four systems, while at Year 7 significant spread has occurred. System B delivers approximately half the average number of interruptions to its customers compared to System C. Investigation into underlying sources of interruptions might reveal differences in comparable maintenance efforts, differing weather patterns, historically differing asset replacement policies, or any number of other factors. Additionally, it might be found that impacts to distribution service have been impacted by upstream service, including power supply. Finally, investigation into changes in reporting processes might also have impacted these year-on-year results.

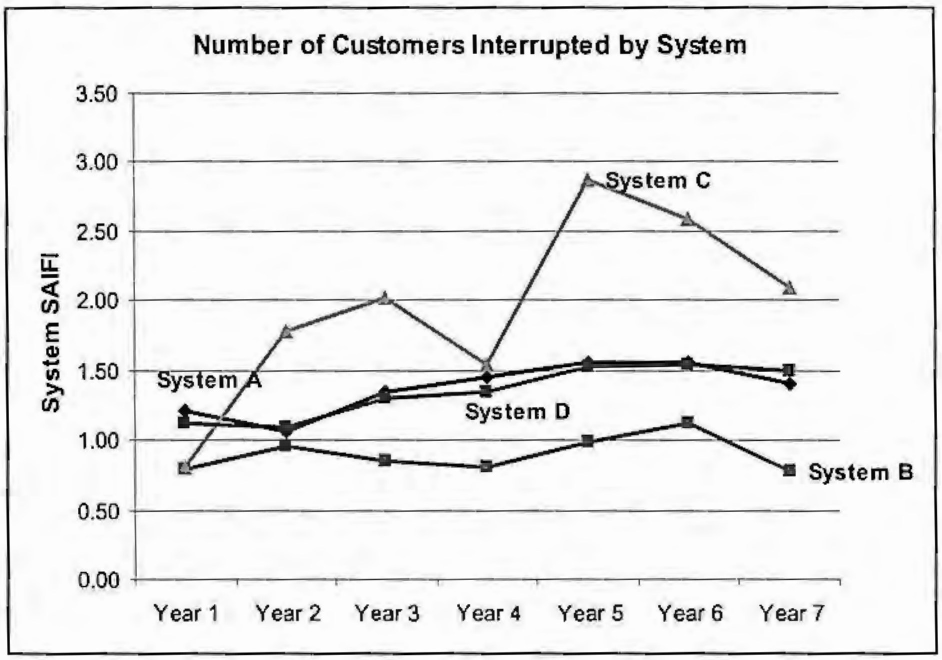


Figure 31 —Breakdown of SAIFI (customer interruptions) by state/region/area/etc.

5.6 Identification, prioritization, program, and process activities to improve reliability

5.6.1 Identification of reliability improvement activities

Identification of reliability problems or concerns can be accomplished through review of information by location, circuit, device, and/or cause type. Location, for example, could be identified through the use of a geographical poor performing pocket analysis, worst performing substation analysis, or worst performing service territory, etc. Circuits or devices could be identified through performance investigation, and deviation from a target performance level [using a metric like SAIFI or the previously-discussed circuit performance indicator (CPI)]. Interruption causes could-be tree problems, cutout failures, or cable failures. In any case, problem identification should support the company's targets, goals, and regulatory requirements.

Reliability indices and metrics are often used as the identification measure in a manner analogous to screening out rock sizes. In explanation, at a system or wide-area level, SAIDI or SAIFI can signal boulders that should be addressed. When drilling further into reliability, more localized system performance, such as district-level SAIDI or SAIFI can be useful, like selecting out large rocks. Next, evaluation at the circuit level, using a circuit's SAIDI or SAIFI or a blended score like CPI, can reveal rocks. And, finally, evaluating local performance issues can be done at a sub-circuit level, such as segment, device, or transformer, can be completed using CEMI, similar to separating gravel from pebbles. In this way, each metric in its proper place can help target the analytical approach and outcomes.

5.6.2 Reliability improvement programs and process

5.6.2.1 Worst performing circuits

One common method for reliability improvement examines the worst performing circuits. The definition of what criteria classifies a circuit as worse than another varies among companies. However, it is often a combination of reliability-related circuit information, sometimes with weighted scoring, which may include, but is not limited to: number of customers interrupted, circuit SAIFI, circuit SAIDI, circuit CAIDI, customer minutes of interruption, customer complaints, age of facilities, customers served, etc. Furthermore, in certain jurisdictions, regulatory authorities have also influenced, prescribed, or accepted the elements of a worst performing circuit program.

5.6.2.2 Programs and processes list

Reliability improvements can be achieved using a variety of programs or processes, such as the following, which are listed below in no particular order:

- Process or procedural changes
  1) Perform step restoration versus completing repairs first
  2) Installation of fault indicators at key locations to reduce travel time to determine fault location
  3) Callout procedures or rules
  4) Additional staffing after hours or on weekends to reduce call out time
  5) Enhanced training programs
- Automation
  1) SCADA
  2) Distribution automation
- Protective device installation and coordination
  1) Reclosers
  2) Fusing lateral taps
  3) Fuse saver schemes
  4) Instantaneous tripping

— System hardening programs
  1) Wildlife guards
  2) Lightning protection
  3) Cable replacement or treatment
  4) Hardware upgrades
  5) Spacer cable
  6) Storm hardening
— Vegetation management (VM)
  1) Performing preventive vegetation maintenance including tree pruning and removal on a cyclical basis.
  2) Performing a mid-cycle condition assessment inspection on feeders
  3) Conducting a dedicated hazard tree inspection and removal program
  4) Application of reliability centered maintenance (RCM) analysis techniques to VM
— Alterations to in-service infrastructure
  1) Converting bare OH conductors to coated systems (e.g., "tree wire," aerial cable, spacer cable)
  2) Reconfiguration and/or relocation of conductors to reduce or avoid the hazard
  3) Overhead to underground conversions
— Inspection and maintenance programs
  1) Visual inspection
  2) Infrared inspection
  3) Cable testing
  4) Pad-mounted equipment inspection
  5) Pole inspection and treatment

5.6.2.3 Comparison of costs to improve reliability

In general, the process for evaluating the cost effectiveness of reliability improvements begins by examining the reliability "what-ifs." Granular interruption information with device level outage details needs to be considered in order to determine whether implementation of a specific program could serve to mitigate the particular outage and customer interruption(s). Historical interruption events need to be evaluated and a determination made as to whether a solution could be implemented that would either eliminate the interruption event, reduce the duration, and/or reduce the number of customers affected. Then cost estimates for the solutions should be prepared. While this approach requires fairly substantial investigation into interruptions and solutions, it is necessary if the goal is to improve reliability in a cost effective manner. For example, if a line tap that serves 50 customers was not fused and experiences a fault event, the upstream circuit breaker, which serves 2500 customers, could lockout. An immediate improvement could be made by fusing the line tap. Any subsequent events on the same line tap would result in 98% fewer customer interruptions.

Another approach to economic reliability comparison is to develop program improvement factors based on interruption history that can prospectively be applied to particular types of interruptions. For instance, if a fuse coordination history demonstrates that properly coordinated circuits typically improve by 35%, this factor could be used to calculate reliability improvement versus implementation cost. The cost to coordinate could then be compared against the reduced customer interruptions and customer minutes interrupted to yield a cost per avoided customer interruption and cost per avoided customer minutes interrupted. Again, depending on which metric is being optimized, one may be preferred for the improvement target over the other. Upon listing each of the projects or programs to be completed, and costs per avoided metric calculated as shown in Table 8, prioritization can be accomplished.

Table 8—Reliability cost versus benefit

District	Circuit	Description	Cost	CMI reduction	$/CMI avoided	Cumulative cost	Cumulative CMI reduction	Cumulative $/CMI avoided
District A	Circuit A	Add recloser	$26,000	75 000	$0.35	$26,000	75 000	0.35
District A	Circuit B	Reliability improvements	$175,000	300 000	$0.58	$201,000	375 000	0.54
District A	Circuit C	Install air break switch	$46,000	75 000	$0.61	$46,000	450 000	0.10
District D	Circuit D	Install fault indicators, reclosers	$96,000	150 000	$0.64	$142,000	600 000	0.24
District B	Circuit E	Reliability improvements	$175,000	250 000	$0.70	$175,000	850 000	0.21
District C	Circuit F	Rebuild west portion of circuit	$40,000	50 000	$0.80	$215,000	900 000	0.24
District D	Circuit G	Implement fuse coordination	$20,000	20 000	$1.00	$20,000	920 000	0.02
District A	Circuit H	Implement fuse coordination	$20,000	15 000	$1.33	$40,000	935 000	0.04

5.6.2.4 Prioritization of various reliability activities

Prioritization of reliability activities begins by developing program improvement metrics, perhaps as described and depicted in Figure 32. After the cost versus benefit routine is conducted, a variety of methods can be performed to optimize the set of activities to be done. In Table 9, a series of cumulative program tables is developed. The optimal selection of capital or operations and maintenance expenditures can be quickly identified, either using this table or using the graphic view in Figure 33. Reliability improvements can be delivered by either operations and maintenance or capital investments; however, each company must consider the best blend of these methods for delivering optimal reliability.

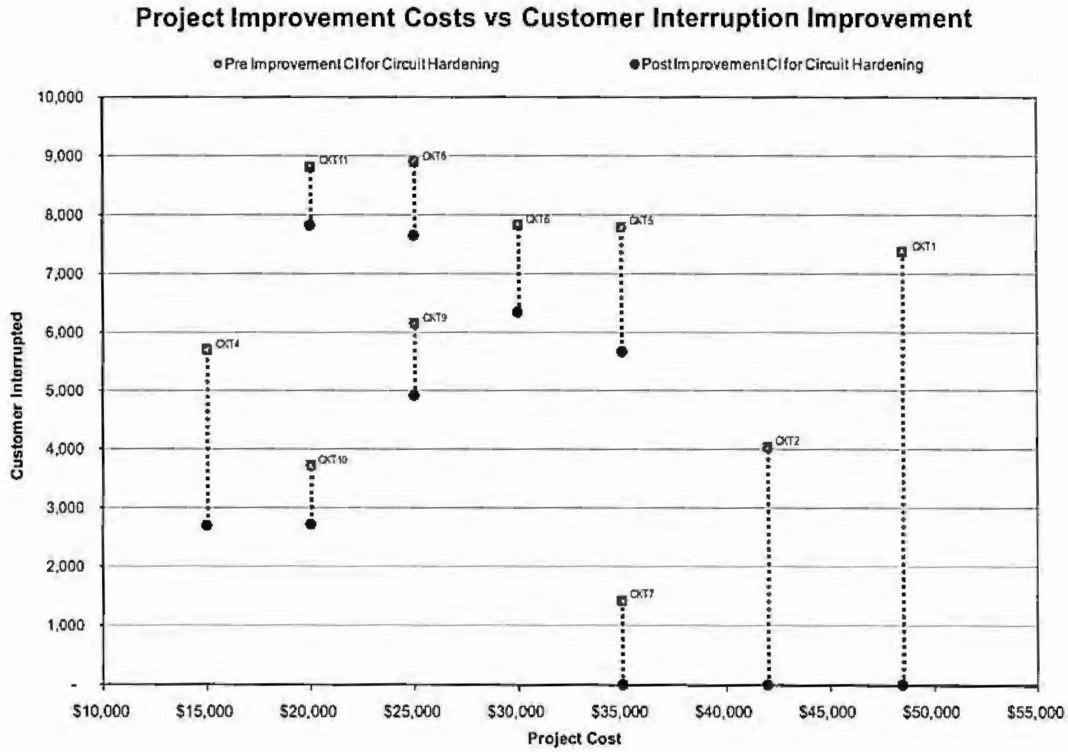


Figure 32—Project improvement cost vs. customer interruptions, before and after

Table 9—Projects ranked by $/improvement (ascending)

CKT	Type of work	Est project $k	Cum $k	Orig. cust ints	Forecast cust ints	Avoided cust ints	$ per avoided cust ints	Cum original cust ints	Cum avoided ints
1	Hardening	40	40	7393	0	7393	5.41	7393	0
2	Hardening	40	80	4033	0	4033	9.92	11 426	0
3	Hardening	50	130	9174	5574	3600	13.89	20 600	5574
4	Hardening	50	180	5715	2715	3000	16.67	26 315	8289
5	Hardening	42.5	222.5	7795	5395	2400	17.71	34 110	13 684
6	Hardening	29.5	252	7849	6349	1500	19.67	41 959	20 033
7	Hardening	28.5	280.5	1432	0	1432	19.90	43 391	20 033

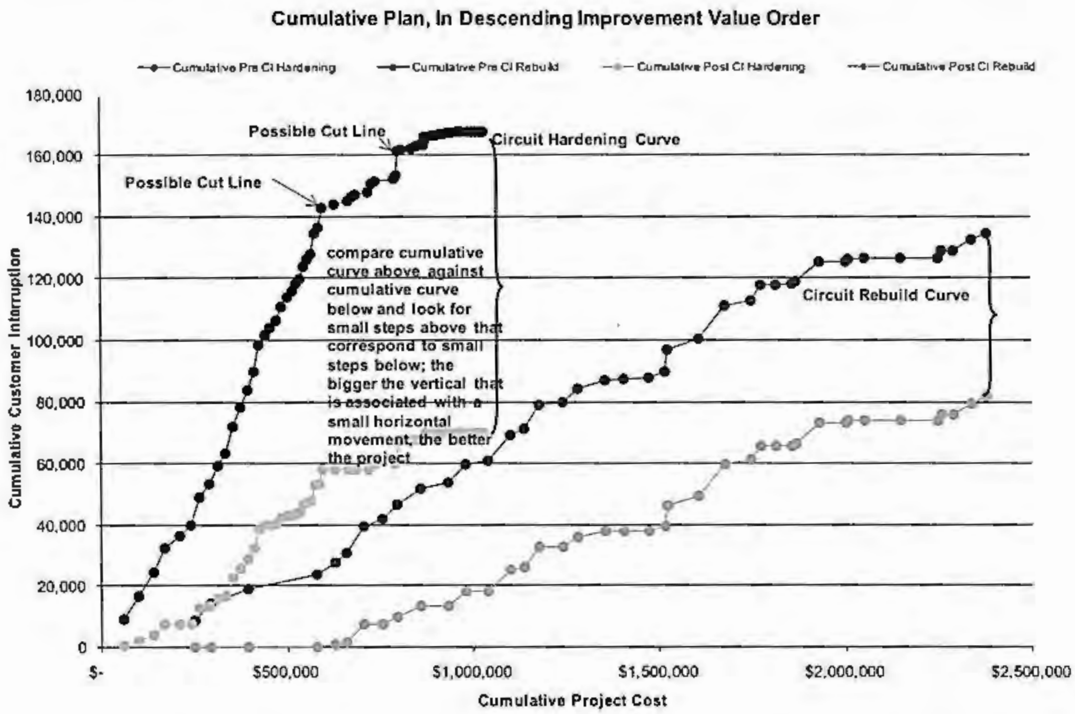


Figure 33—Graphical optimization curve: cumulative impact by program, ascending in cost/improvement

With the previous graphic and tables, as budgets and projects are being considered, potential cut lines can be drawn which are able to be linked to forecast performance.

5.6.2.5 Projected value of reliability improvements considering customer values for higher reliability

In 5.3, an approach to prioritizing improvements using circuit deliverability was explored. This approach can be further developed and reliability improvements can be considered by incorporating the value of reliability to customers by their class.

Economic benefits from reliability investments can flow to utilities and to their customers. Reliability benefits flow to utilities in the form of reduced operating and maintenance costs and reduced costs of service restoration. Benefits flow to customers in the form of the avoided economic losses they experience due to unreliable electrical service. Consider this example. A specific utility plans to spend $1,755,000 on reliability improvements in a given year. These investments are expected to provide a 0.05 reduction in non-major event SAIFI and a 5.18 reduction in non-major event SAIDI. Table 10 summarizes the number of customers by sector and the estimated benefits that are associated with the SAIFI and SAIDI improvements. The results are shown after major events are excluded. On aggregate, the $1,755,000 reliability investment is expected to provide around $9 million in benefits to customers. Almost all of the benefits experienced by these reliability improvement investments occur as a result of the high value that customers in certain classes place upon the impact of an interruption. This high value can be due to lost product cost or other measures that are known to the customer. In general, it is more attributed to the small commercial and industrial and medium/large commercial and industrial sectors. In this example, residential customers would experience only about 2% of the overall benefits of the improvement. However, on a customer-wide basis, the estimated benefit per customer is $11.4 to $11.9. Considering that this benefit accrues from a $1,755,000 investment ($2.3 per customer), this analysis suggests that the reliability improvement is highly cost-effective from the commercial and industrial customer's perspective.

Table 10—Estimated benefits of improvement in reliability

Sector	Number of customers	Underlying SAIFI/SAIDI	
		Aggregate $	$ per customer
Medium and large C&I (over 50 000 annual kWh)	19 341	$4,802,666	$248.3
Small C&I (under 50 000 annual kWh)	92 000	$4,250,767	$46.2
Residential	659 025	$148,186	$0.2
All customers	770 366	$9,201,620	$11.9

To estimate the value of this reliability improvement for customers, it is necessary to calculate total costs with and without the investment. Total interruption costs with the investment minus total costs without the investment equal the value of the reliability improvement to customers. Basically, the benefit to the customer equals the cost reduction that the investment provides. The expected interruption costs in each scenario are taken from Sullivan et al. [B4]. This report presents the results from a meta-analysis of 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over a 16-year period from 1989 to 2005. The results are presented in the form of customer impact functions which relate customer interruption costs as a function of customer class, outage duration/time of day/season, and a variety of customer demographic or firm-graphic factors. These customer impact functions were used to estimate the interruption costs in each scenario and the benefit that the expected reliability improvement provides.

5.6.2.6 Consideration of asset purchase (capital) versus operation and maintenance (O&M) expense in prioritizing reliability projects

There are a variety of approaches taken to assess the financial impact of reliability improvements. One approach makes no distinction between capital and O&M costs and considers only the first cost of the intended action. It is sometimes used as an initial screening criterion. Sophisticated financial analysis is often used to assess large and complex projects. This would include proper accounting for both capital and O&M components and would consider total owned cost. There is a continuum of potentially useful approaches between these two approaches.

It is important to understand the basic accounting treatment of the cost of capital and O&M reliability improvements. The costs of O&M improvements to reliability are treated as expenses. They represent costs that offset revenues at the time they are incurred and have an immediate and direct impact on bottom line profitability. In contrast, the costs of capital improvements to reliability are treated as investments. They are added to the capital asset base that the utility earns on. As they age, they depreciate, and the cost of depreciation is treated as an expense. This effectively spreads the economic impacts of the reliability improvement over time.

Table 11 provides a high-level construct of the categories of cost and income that would typically be considered in assessing the economic impact of either O&M or capital projects intended as reliability improvement. Note that in many cases a capital investment could also include an O&M component. Capital investments also typically include some consideration of the economic benefit of the capital addition to plant.

Table 11 —Simple comparison of costs when comparing capital and O&M investments

Financial consideration	O&M reliability improvement	Capital reliability improvement
First cost	−100% cost is treated as expense the year it is incurred	− Cost is treated as a capital investment that is added to rate base.
Total owned cost	− Estimated future cost to operate or maintain if any.	− Estimated future cost to operate or maintain. - Depreciation over time
Value of expected reliability improvement	+ Avoided cost of poor reliability over some time period.	+ Avoided cost of poor reliability over some time period.
Value of capital improvement	Not applicable	+ Rate of return on capital addition to plant.

An O&M expense has an immediate financial impact to the bottom line, whereas the cost of a capital investment is spread over time and represents an opportunity for earnings. An approach is that a financial analysis model be constructed that makes an assessment of the differences in accounting treatment of capital and O&M costs and uses a longer period for assessment. The level of intensity of this analysis should be appropriate for the intended use and need. A simple comparison can be quite useful in quickly creating a high level list of potential reliability improvement options.

For example, one utility compared a potential additional vegetation management program to the installation of automated three-phase reclosers. When considering only first-time costs against customer interruptions avoided, reclosers would cost approximately $100 per avoided customer interruption, while supplemental vegetation management would cost about $50 per avoided customer interruption. But reclosers would continue to provide customer interruptions savings for many years, while the additional vegetation management spending would need to be continued on an annual basis in order to sustain customer interruption savings. A 20-year present value analysis considering depreciation, taxes, and a discount factor led to estimated costs of about $9 per annual avoided customer interruption for reclosers and about $30 per annual avoided customer interruption for additional vegetation management.

5.6.2.7 Evaluation of the effectiveness of reliability improvement programs

Upon delivery of a reliability improvement program, the next logical question to be answered is, "How much improvement was received for the actual expenditures?" There are many ways to determine the value delivered, but measurement of key performance variables should underpin the assessment. Thus, for the examples outlined previously, customer interruptions or customer minutes interrupted would be the key variables to include in the analysis.

There are many different ways that can be used to compare the effectiveness of reliability improvement programs. In the most basic way, baseline performance and subsequent improvement levels can be compared for a "before" versus "after" performance. There needs to be recognition when making this comparison that random events could possibly lead to an erroneous conclusion. A more sophisticated method could be prepared using statistical process control techniques leading to more statistically significant conclusions for the population being evaluated. Alternatively, use of control populations to measure year-by-year variations can be devised and compared against improvement populations.

5.6.2.7.1 Evaluation effectiveness using baseline year metrics

In the example below, the approach taken is to establish baseline performance in Year 1 and compare performance in the year after reliability improvement work was completed against the baseline performance. Thus, if the baseline year is Year 1 and reliability improvement projects are completed in Year 2, then Year 3 performance (which includes the full effects of the projects) would be compared to Year 1. This approach is shown in Figure 34 and Figure 35. It is advised that some method for handling anomalous events be considered and that sufficient projects be measured so that individual outliers do not dominate any analysis.

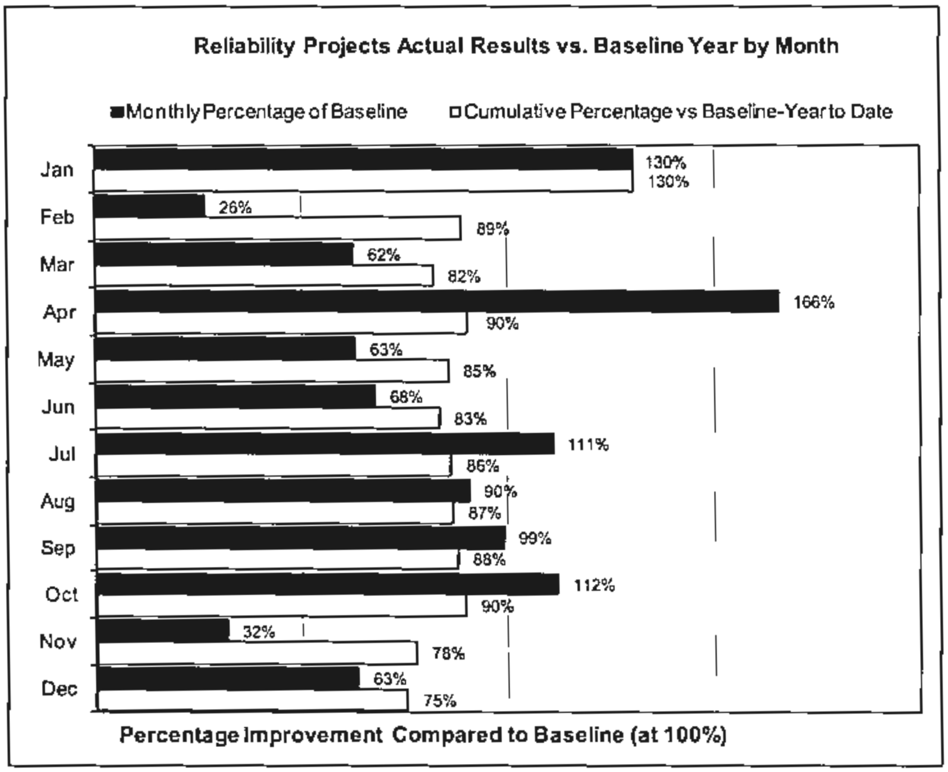


Figure 34—Actual results versus baseline year comparison

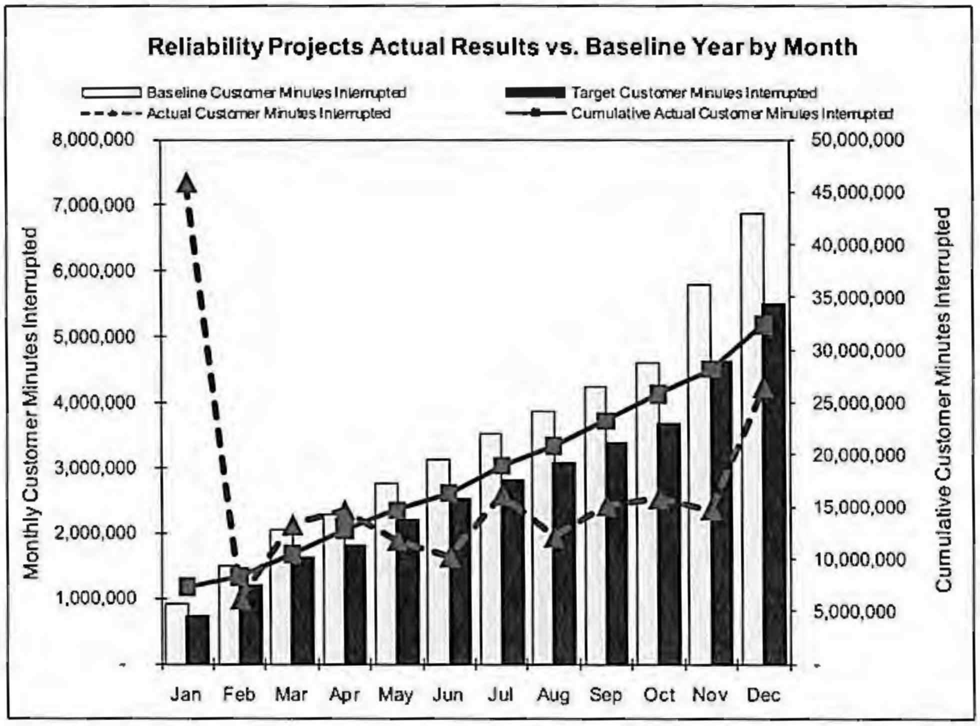


Figure 35—Actual monthly performance, individual and cumulative customer minutes interrupted

It is also important to recognize in Fignre 34 and Figure 35 that some purely random behavior that has nothing to do with improvement efforts is captured in post-program vs. pre-program analyses. In order to determine the effectiveness of any given set of reliability improvements, performance after the improvements can be compared against performance prior to any improvements, which may be considered the baseline performance against which comparisons could be made. While there are concerns regarding the comparability of the data, if these concerns are addressed, evaluation of improvement can be performed as in the two charts in Fignre 34 and Figure 35. Figure 34 shows that if you establish performance against the baselines, month-to-month improvements are shown. So, for instance, at year-end a 25% improvement over the baseline was measured. Figure 35 shows the month-to-month performance against a targeted improvement.

5.6.2.7.2 Temporal variations in evaluating the effectiveness of improvement programs

Reliability measures such as SAIFI, SAIDI, and CAIDI change from year to year. This temporal variation is comprised of two basic components: random (or stochastic) variation and systematic (or non-stochastic) variation. For example, random interruption causes may include wildlife, public, or weather events, while a systematic interruption cause may include equipment failure. Random variation is caused by processes that involve chance or probability, whereas systematic variation stems from non-random processes such as seasonal weather changes.

This is explained at least in part by what is known in statistics as regression to the mean. Worst performing circuits are identified in a given year in part due to underlying reliability weaknesses relative to other circuits and in part due to the purely random nature of the outage events that occurred during the period that provides data for the circuit selection. The underlying reliability of the circuits is improved by the remedial actions taken to the extent that the actions were proper responses to the reliability weaknesses, bnt the statistical tendency for worst perfonning circuits to regress toward the mean is random. The improved reliability measured after a remedial program should not be taken as an estimate of underlying improvement in system reliability, but recognized as part system improvement, which may be repeated, and part random behavior, which cannot be repeated.

Variation of reliability measures makes it difficult to detect changes caused by actions undertaken to improve reliability. The reason is that performance changes caused by reliability improvement activities are often masked by the variation attributable to random and other systematic processes. In other words, a "signal" associated with the reliability improvement activity is frequently masked by "background noise." When specifying parameters to assemble the data, the analyst needs to try to minimize the impact of the background noise. This can be done by ensuring a sufficiently large population, assembling a long enough time period, or by narrowing out normal causes (certain types of outages) which are "background related."

After the parameters have been appropriately specified, there are many suitable tools and methods to help deal with reliability measures subject to variation. As a general rule, such tools and methods have the goal of presenting measures in a way that preserves the context of the contributing data. Employing these can prevent confusing a significant change brought about by an assignable cause with a change caused by chance occurrence.

5.6.2.7.3 Using statistical process control to evaluate the effectiveness of reliability improvement programs

Another method to help identify and manage measurement variability includes using statistical process control methods. This approach provides a technique for identifying a significant change in a process, the output of which is measured by a quantitative performance indicator such as SAIFI or SAIDI. It is typically important to know about these changes in order to assure that reliability improvement programs are having their intended effect, but there is a complication. Some of the changes which occur in performance indicators are random in nature and do not involve changes directly attributable to the reliability improvement programs. To address this problem, one can employ a process behavior or control chart that aids in distinguishing between random variation and variation caused by changes to the underlying process (Shewhart [B3]).

Control charts identify the expected range of performance for a given process. If the output is within the range, then any variation may be considered to be not statistically significant. If, however, the range falls outside the boundaries of normal, it signals a noteworthy change. Thus, these charts can help establish whether a change is attributable to an assignable cause or is the result of chance.

Shown in Figure 36 is an example of reliability performance data plotted on a control chart. The upper and lower control limits (UCL and LCL) on the chart are three standard deviations from the mean and are calculated from the median moving range of successive data points multiplied by a constant. When a single data point exceeds one of the limits, the underlying process has likely changed and the cause can usually be traced to an assignable cause. (In other words, it is very unlikely the change was the result of random variation in the data.)

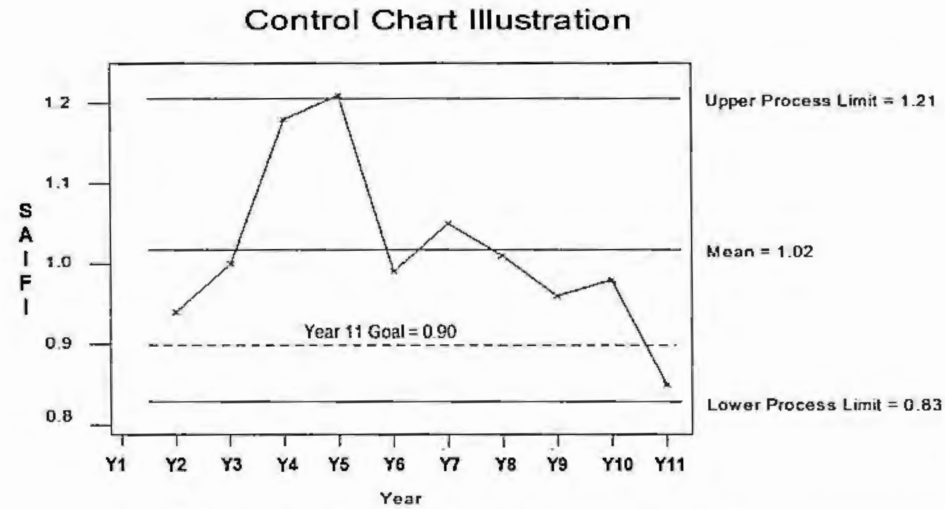


Figure 36—Control charts of annual SAIFI

To illustrate the concept, shown in Figure 36, consider the hypothetical case of a utility that set an annual SAIFI goal of 0.90. The lower process limit was calculated to be 0.83, while the upper process limit was calculated to be 1.21. In order to reach this goal, the utility also implemented a tap fuse installation program at the start of the year. At the end of the year, SAIFI was calculated to have a value of 0.85. The utility thus concluded their SAIFI goal was achieved because of the tap fuse program.

Upon further examination with the control chart, however, the SAIFI value fell within the range of historical variation bounded by the upper and lower process limits shown. The utility's conclusion that it met the goal due to its tap fuse program could be incorrect since it fell within the historical boundaries indicated by the upper and lower process control limits. On the other hand, a measured value of SAIFI less than the lower process control limit of 0.83 would have given strong statistical indication that the tap fuse program contributed to reaching the goal.

Reliability measures should always be interpreted with knowledge of the random and systematic variation which occurs in contributing processes. To do otherwise risks drawing incorrect conclusions and unnecessary expenditure of time, effort, and money.

Further use of control charts could demonstrate the need for program modifications by evaluating reliability within a given year, perhaps even on a subset of feeders. For illustration purposes, such a situation would occur if eleven consecutive monthly values of SAIFI exhibit random variation while the twelfth value exceeds the UCL. A subsequent investigation of the last data point might conclude that a single, large-scale outage of a feeder circuit caused by tree contact was responsible for the outage. Further study might lead to a specific assignable cause for the tree contact, perhaps that trim clearances are not sufficient. Appropriate corrective actions could then be taken to prevent recurrence of the problem.

In addition to one point exceeding a control limit, other patterns in the data can also signal significant changes in the process which are attributable to a special cause. For example, six consecutive decreasing points would be necessary to indicate a significant downward trend. Significant process changes could also be indicated by one point more than three standard deviations from the mean, nine points in a row on the same side of the mean, or two out of three points are more than two standard deviations from the mean.

It is also possible that no significant patterns exist in the data being plotted. Referring to Figure 36, while the overall trend in SAIFI for this example is encouraging, there are fewer than six consecutive points that are decreasing in value. Four consecutive decreasing points may indicate a change in the process but at a decreased level of confidence.

If sufficient data is available, this graph could also be divided into "before" and "after" regions. Control limits and mean values for each region could then be determined in order to gain additional insight into the effectiveness of reliability improvement projects.

5.6.2.7.4 Using control populations to evaluate the effectiveness of reliability improvement programs

As stated previously, another method which yields higher confidence of true cause and effect improvement methods is the application of design-of-experiments (DOE) methodologies.

One DOE technique for resolving causal factors is to establish a control group which can be used to benchmark performance of a treatment group. Ideally this would occur in a controlled setting where test subjects are randomly assigned to one of the two groups. Test subject performance before and after the treatment for both groups could then be used to determine if a significant change was caused by the treatment. Another practical example of this approach would be to analyze SAIFI resulting from tap fuses and SAIFI resulting from the upstream device that would otherwise have operated for specific fault events. For example, installing more tap fuses may prevent circuit level outages. A decline in circuit level outages and an increase in fuse level outages would provide additional confirmation that the fuse program worked. Circuit level SAIFI would decrease much more than fuse SAIFI increases.

There may also be situations which afford opportunities for measurement of treatment and control groups which do not occur in an experimental setting. For example, to determine if tree trimming is effective at reducing customer interruptions as a result of a storm, it may be possible to compare the performance of circuits in the storm area that were trimmed in the previous year to those trimmed three years prior to the storm, as shown in Figure 37. Assuming a sufficient sample size and adequate variation in trim dates for circuits in the storm area, comparison of the groups' performances would lead to a reasonably accurate quantification of avoided customer interruptions attributable to expanded clearance or more frequent tree trimming. Dividing the avoided customer interruptions into the trim costs would provide a single value for assessing the average cost effectiveness of tree trimming for this particular situation.

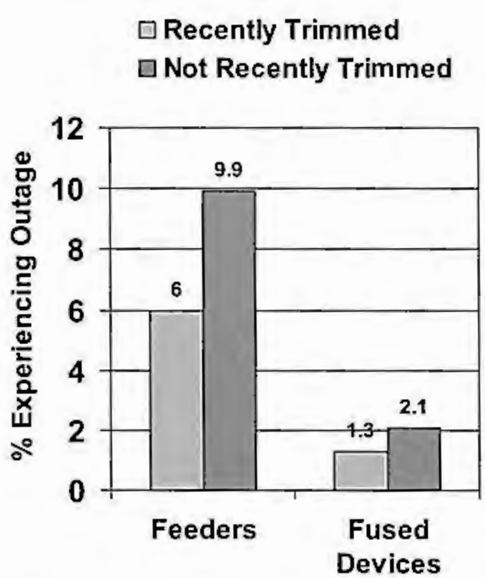


Figure 37—Comparison of circuit performance during a single storm event

For the purpose of evaluating program value, the primary benefits of increasing technical complexity are usually a decrease in measurement uncertainty and an increase in the confidence of conclusions. As a general rule, the level of technical complexity depends on the evaluation's end-use. Additional factors to consider are availability of data and resources to conduct the analysis. Depending on the data's use, a statement of estimated uncertainty may be beneficial to allow audiences to understand how confident one should be when evaluating these conclusions.

5.7 Design, construction, and operating practices

5.7.1 Design and construction

An electric utility's design, construction, and material standards play a key role in delivering electricity reliably. For example, reliability issues may be directly related to the methods crews use to replace failed equipment or install new equipment. Many utilities have inspection programs to verify that new construction and rebuilds incorporate the current company design, material, and procedural standards. In many cases, prior installation practices cause future reliability concerns. Therefore, if a crew does not make repairs using current company construction standards, the full potential of reliability improvement may not be achieved. Inspecting a percentage of these jobs can reveal deviations from existing standards and direct crews towards proper future construction.

Training personnel on the current construction and maintenance standards is critical to achieve reliability improvement expected by customers. This training can include topics such as the correct or most efficient placement of arresters and the proper practice and techniques for installing new terminators on cable. Training before the initial change in procedures and/or material as well as follow up training is critical to success.

Below are ways that a utility with standard design and construction practices can affect its reliability results in a positive way:

- All design and construction practices should be documented
- Standardize maintenance schedules and practices for equipment, such as line regulators, reclosers, capacitors, poles, grounds, arresters, and switches
- Standardize input request for outage data related to material item, manufacturer, vintage, and installation practice (construction type of structure) at damage point
- Define precise material specifications to procure the material or equipment as expected
- Implement practices to remove, repair, or replace components found to be unreliable
- Maintain contingency support by retaining circuit and substation capacity
- Ensure proper tools and proper use of tools for installing material and equipment
- Train and inspect concerning standard guying of structures to ensure compliance with code, working practices, and standards
- Research new products and/or practices to improve reliability
- Standardize testing procedures for cables and other materials or equipment
- Standardize replacement practices for vintage equipment with reliability history: cable failures in a run, splices in an overhead span, and vintage arresters
- Standardize required service installation by electrician at points of service

Construction of an electric system is accomplished using a utility's standard materials and procedures. There are circumstances, however, where solutions requiring new types of materials or procedures are needed. When new or different types of materials are used with other accepted construction practices, the new installation should be investigated for compliance to standards. This compliance often includes aspects such as safety, strength, and environmental resilience.

Another important factor deals with maintaining the system's reliability profile. An example of this is replacing a distribution wood pole structure and cross arm assembly with a steel pole and cross arm counterpart. While the material strengths and construction techniques are similar, the steel pole structure is quite different when comparing surge protection requirements. Unless the aspects of maintaining an adequate basic insulation level (BIL) or critical flash-over (CFO) are researched and applied, a reduction of reliability will most certainly occur.

5.7.2 Operating practices

Operating practices have the ability to significantly impact system reliability. Fundamentally, there are many alternatives that can be used to impact either the number of customers impacted by an outage or the duration of the outage. For example, troubleshooter or crew shifts can impact how promptly restoration can be performed. Another consideration is how often troubleshooters are able to restore power on initial response. If a crew is required to complete the restoration, it will impact reliability, notably the duration and outage restoration metrics, SAIDI and CAIDI. Based on system settings, outage events can be momentary interruptions rather than sustained interruptions. Performing temporary restorations, including system switching, can result in shorter duration outages, but result in greater efforts expended by crew resources.

5.7.2.1 Step restoration versus waiting for full restore

There are two schools of thought when restoring customers. The first is to complete all repairs and then restore all the customers downstream of the operating device. The second is to make safe, then restore as many customers as possible through switching and other means before beginning repairs. The first method may make more efficient use of resources, but this can create longer interruption durations for the majority of customers affected, thus making duration reliability indices such as CAIDI and SAIDI worse. The system design, however, would not require as many switching positions along a circuit. The second method requires more time expended choosing the best way to get customers back in service with a possible multitude of switching options. Thereafter, the repair and restoration can be completed.

The choice between these two options is also affected by the amount of repair required to restore service. A utility typically would not spend an hour switching customers to other circuits when a ten minute repair would completely restore service. As typical with reliability issues, no one solution works for all situations.

5.7.2.2 Fuse save versus fuse blow approaches

When designing the system protective schemes, a fundamental determination of whether to save fuses needs to be considered. In systems which have a high incidence of transient faults, a fuse save scheme may be beneficial. If however, faults tend to be more permanent in nature, or if detection of the location of the transient fault is important, fuse blow schemes may be a better choice. Finally it may be appropriate to set substation relays to recognize what form of fault events occur on the system. This is discussed at greater length in Annex B. It is important to note that a fuse blow scheme minimizes the temporary interruptions that all customers will experience during a fault event. For further discussion, see Annex B.

5.8 Benchmarking and goal setting

5.8.1 Benchmarking

Benchmarking and service level goal-setting can assist regulators and utilities in developing rate structures which can support the appropriate development and maintenance of the electric system. These benchmarks may be useful in developing policies to provide impetus for company operations and investment strategies. Additionally, companies may use benchmarking methods to target new programs, evaluate benefits of improved system technologies, and assess the efficacy of implemented practices.

As utility companies themselves cope with downward rate pressures and increasing service level expectations, executives are increasingly interested in how their service levels compare to others in their industry sector, geographic area, etc. These executives want to know their ranking relative to peer utilities, along with what expenditures will attain and/or retain the desired ranking. Benchmarking results can help these utility executives set service level goals and assists in the development of adequate funding levels for the various sectors of their companies.

In general, most benchmark studies focus on SAIDI, SAIFI, and CAIDI, and attempt to create apples-to-apples comparisons by segmenting out "major events." Major events must be explicitly identified since companies may use a variety of definitions. Additionally, focus should be given to whether interruptions are the result of external forces on the distribution system or from outside the distribution system, e.g., power supply interruptions. Figure 38 is an example benchmark chart that demonstrates an annual period SAIDI for each utility within the peer group.

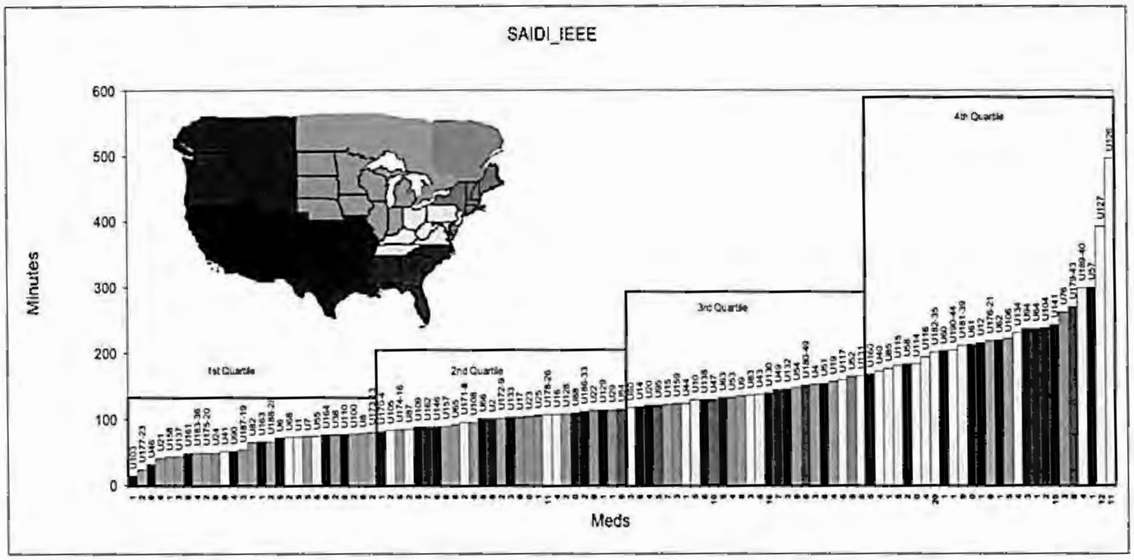


Figure 38—SAIDI benchmark by utility

5.8.1.1 Benchmarking challenges

While benchmarking is informative, in order to yield proper conclusions, fundamental differences between utilities must be considered. First, as outage management systems (OMS) change, underlying data may also change. For instance, many companies have implemented an automated OMS, which often results in higher, but more accurate, reported results. Also, different OMS systems model outages differently and that may result in inconsistent comparisons; i.e., network connectivity to the customer or transformer. Further, comparing one utility to another can be problematic as geography, environment, vegetation densities, customer densities, size, age, or type of construction will result in varying reliability index results.

5.8.2 Internal goal-setting

Generally, companies should set internal reliability goals. This can be done at the company and sub-company levels, such as regional. Data is typically available by geographic area, and breaking up the company's data into the geographic areas due to different climates, customer densities, and type of construction allows for sub-company goal setting. It may be necessary to ensure that when more specific goals are developed for sub-areas (whether regional or departmentally-based) they should be aggregately compatible with corporate goals. If all sub-area goals are met, the corporate goal must be met. Additional approaches for developing regional targets are included in Annex C.

Table 12 shows a company and its five operating areas' historical SAIDI and SAIFI, along with each area's customer count. Each of these areas has different factors that drive the reliability numbers and are well known, but not necessarily documented well enough for a regression analysis to be of value. The corresponding proposed reliability goals take these situations into account. As can be seen, the Central area is a large urban area with a high SAIFI value but with the best SAIDI value, indicating that CAIDI is low due to a good response time. Any improvement in goals may include focus on reducing the quantity of outages and customer interruptions. The Northwest, Southeast, and Northeast areas have good SAIFI numbers compared to the company average, but the response time is slow due to these areas being more rural, with long travel times and limited 24/7 outage response coverage. The goals in these areas may include a focus on reducing CAIDI.

Table 12—Regional reliability metrics

Area	Historical SAIDI	Historical SAIFI	Historical CAIDI	Customer count	Historical CI	Proposed SAIDI goal	Proposed SAIFI goal	Proposed CAIDI
Northwest	107.3	0.72	149.0	50 000	36 000	106.3	0.72	147.6
Southeast	136.2	0.80	170.3	10 000	8000	121.1	0.75	161.5
Central	91.9	1.23	74.7	450 000	553 500	88.9	1.13	78.7
Southwest	95.4	1.30	73.4	175 000	227 500	85.3	1.15	74.2
Northeast	121.2	0.59	205.9	80 000	47 100	123.4	0.62	199.0
Total	97.4	1.14	85.4	765 000	872 100	93.24	1.05	88.8

5.9 External stakeholders

5.9.1 Overview

There has been an increasing demand for reliability information by external stakeholders. These stakeholders can include governmental officials, state regulatory commissions, economic development groups, customers, and interveners. Reliability data can also be useful when preparing testimony for regulators.

5.9.2 Use by regulators

Regulators are increasingly more interested in reliability delivered by utilities. Providing reliability data or trends on an annual basis can be beneficial, but additional information should be provided in order to establish a proper context. Some regulators use reliability indices to implement performance based rates (PBR).

Supplying reliability statistics for large storms to regulators may be required to show a utility's storm response performance. Many regulators are actively involved in evaluating the effectiveness of storm responses, which can be evaluated by data such as shown in Figure 39. The start of the event is indicated by the first peak. The peak effect on customers and the final customer restoration can also be determined.

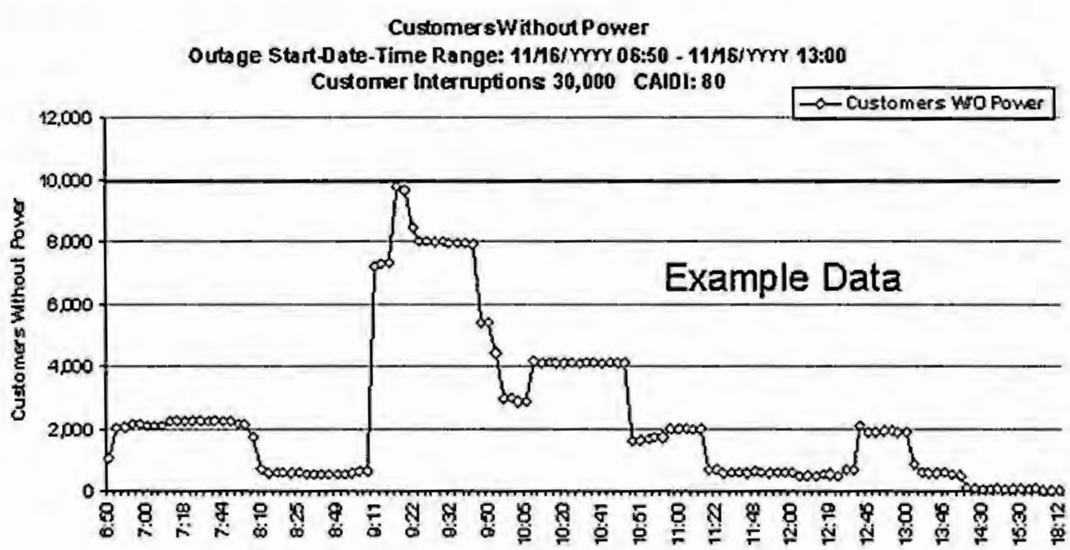


Figure 39—Storm statistics—remaining customers without power

5.9.3 Use by public officials and governmental agencies

The demand for reliability data by public and governmental officials is increasing. When communities or customers perceive that their level of service is not adequate, they may call upon their area officials to take action. Therefore, cities with municipal agreements and legislative officials have also become more interested in reliability metrics. As a minimum, the use of average system availability can be useful to describe the system's underlying reliability. Figure 40 and Figure 41 show how reliability metrics could be shown for a local area.

Another use of reliability data by governmental agencies can involve the historical evaluation of reliability metrics for agencies responsible for emergency planning. They may request outage frequency and duration for both normal and major event days. While past performance does not predict future experiences, it can be beneficial in developing a general understanding of the system reliability for which these agencies plan.

Providing statistical information to a company's public spokesperson is vital in maintaining ongoing relationships with governmental officials. Educating public officials on reliability indices and providing explanations of why interruptions occur can be beneficial. It can also be helpful to provide this information on a periodic basis.

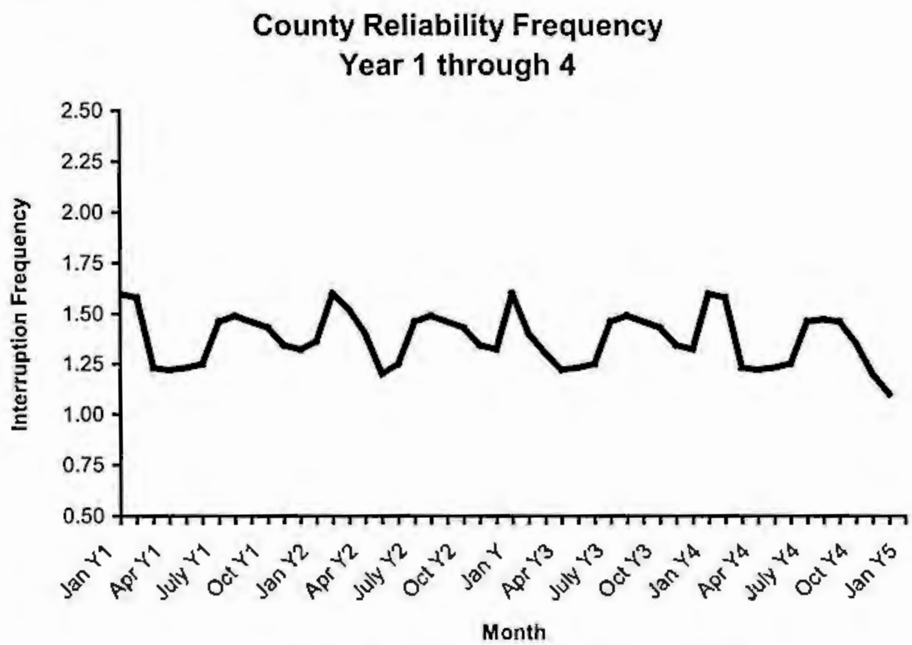


Figure 40 —Local area reliability performance

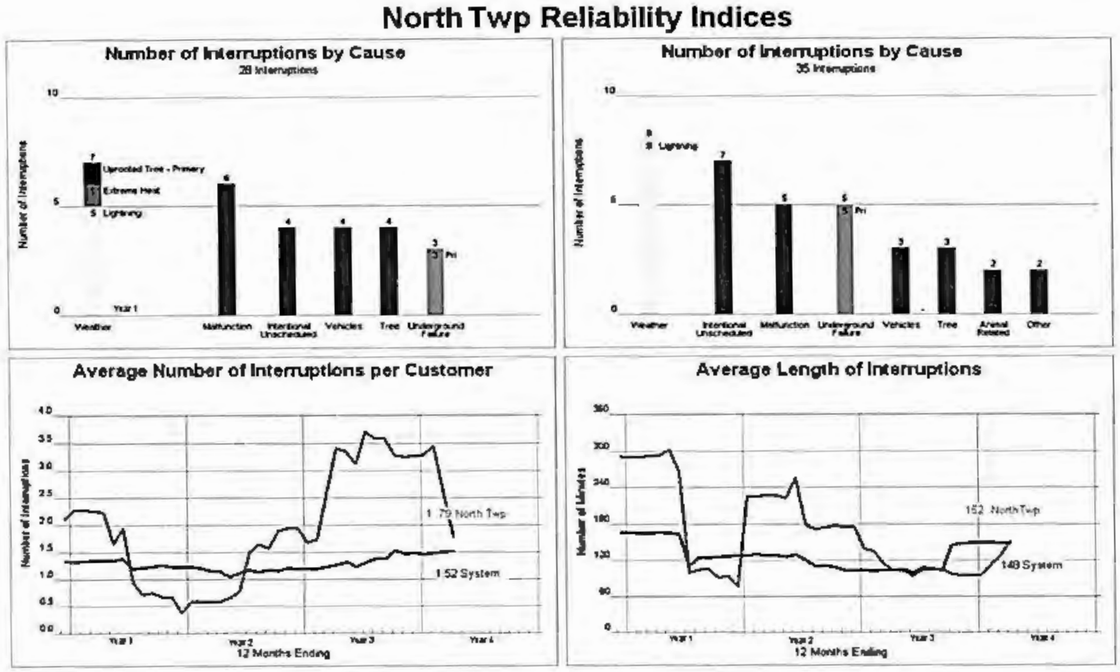


Figure 41—Local area reliability performance with causes

5.9.4 Use for economic development

Most industrial and commercial customers are concerned with service interruptions when researching potential new sites. It can be beneficial to a potential customer to obtain reliability history for a premise or a circuit. In the case where a new circuit may be needed because of a high load addition, it may be necessary to provide the reliability of the adjacent service area to the potential customer.

5.9.5 Use for customers

Some regulatory commissions have established requirements that utilities provide customer-level reliability performance upon request by the customer. Several states mandate that the utility provide customers interruption history. For instance, one state specifies a two-year history must be provided, while in another state, a customer may request up to five years of history. Other customer-specific information may be requested such as maximum outage durations that a customer experienced during a period in order to size a battery backup system.

5.10 Data use and reporting

5.10.1 Near real time external interruption reporting

Interruption reporting is becoming more critical to governing agencies and to the media, especially in large metropolitan areas. Customer satisfaction surveys have shown that electric customers want to know when their power will be restored so that they can plan appropriately. Accurately estimated interruption restore times are critical to meet today's level of customer expectations. Media expects timely and accurate interruption information so that they can provide trusted television and radio reports.

Real time customer interruption information can be delivered to external entities via a variety of means, including the web, faxes, telephones, smartphones, social media, etc. The information can be in tabular, graphical, or geographical information, as in Fignre 42. Information such as circuits, transformers, outage causes, and damage assessment and estimated restoration times can be displayed. Security concerns must be addressed for reporting information to external parties.

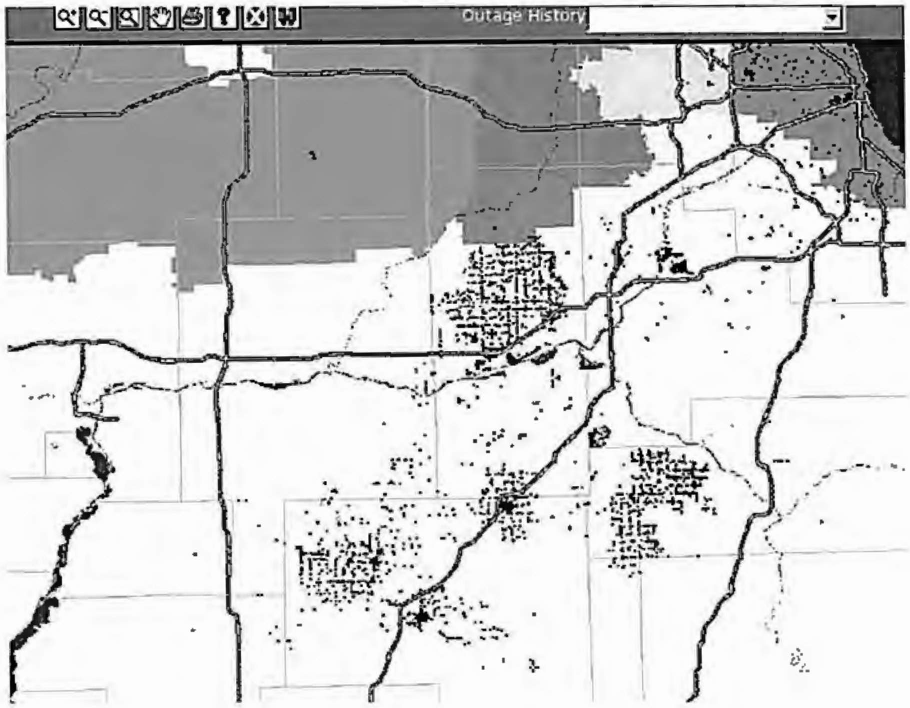


Figure 42—Example of geographic interruption information

External interfacing departments at the utilities, such as public affairs, regulatory, and communication personnel, now have the ability to provide up-to-the-minute information to municipal officials and media outlets. Customer service personnel can provide the same timely data directly to customers so that they can make informed decisions, such as whether or not to stay at a family member's house or a hotel during a large-scale storm, or industrial customers can decide whether or not to release employees for the remainder of the shift.

Further, many utilities have begun to provide their customers with the web-based ability to geographically view area outages on the system and to securely report and track their individual interruptions throughout the event. Figure 43 provides an example of the public customer interruption information available on some utilities' web sites, which includes the number of customers interrupted within various areas.

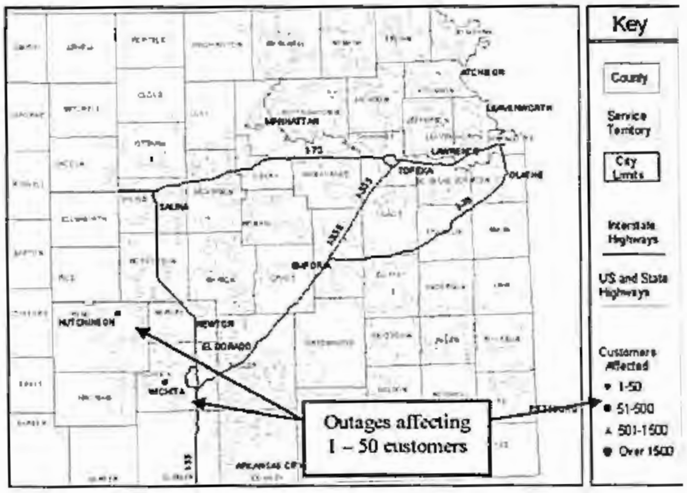


Figure 43—Example of geographical customer interruptions

5.10.2 Internal reporting

Real time outage data is extremely useful for internal utility reporting and analysis. It allows restoration management teams to make informed decisions on the appropriate level of field staffing for the restoration process. Based on current field staffing, decisions on when additional crews may be needed can be made in order to meet estimated interruption restoration times provided to external entities.

Many utilities have internal reliability goals and targets, such as CAIDI, SAIDI, SAIFI, and CEMI. Up-to-the-minute data sources are now available for company employees to measure their department's own performance when compared to goals.

5.10.2.1 Daily, weekly, monthly, and annual operating reporting

Many utilities have developed operational scorecards, or dashboards, that include reliability metrics. These can provide meaningful comparisons for an area, for the period, from year to year. When well-communicated throughout the operational organization, they can serve to focus key line staff attention to reliability. Figure 44 and Figure 45 provide several views of elements of one utility's scorecard.

For example, using the local area CAIDI statistics, the utility can identify areas of the company with the shortest and longest average customer restoration times and determine if there are best practices being utilized in one area that should be considered for implementation system wide. Using the district, region, or state SAIDI and SAIFI, the utility can identify those areas of the company with the highest number of interruptions and/or the highest customer minutes of interruption for further review.

As part of the CAIDI review and comparison between operating areas of the utility, the utility may want to compare the average restoration times, or average outage CAIDI, based on the time-of-day the outage began, i.e., from a typical crew's work day hours versus after-hours and weekends. With this information, the utility should be able to evaluate the benefits, and/or the needs, for additional swing shift or weekend staffing on duty primarily for service restoration purposes. Also, a comparison of various crews in various outage situations can be evaluated.

TIME TO FIRST RESTORATION

Time to first restoration is the time when Company A has been notified of an outage to when the first customers are restored.

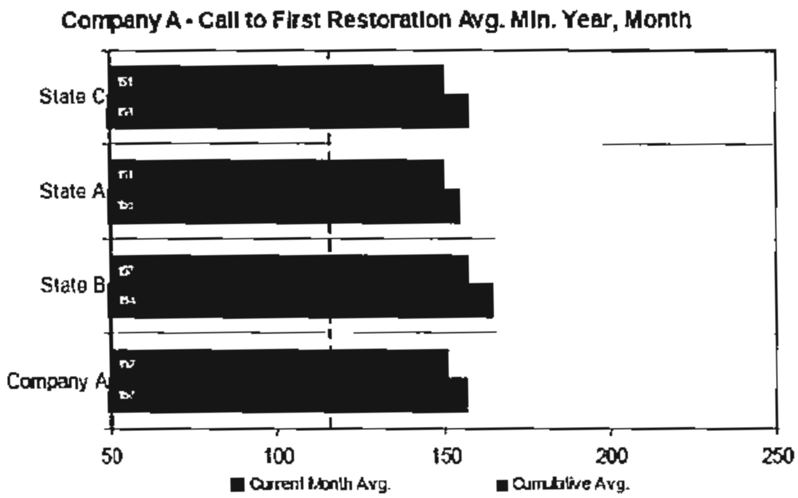


Figure 44—Time to first restoration scorecard

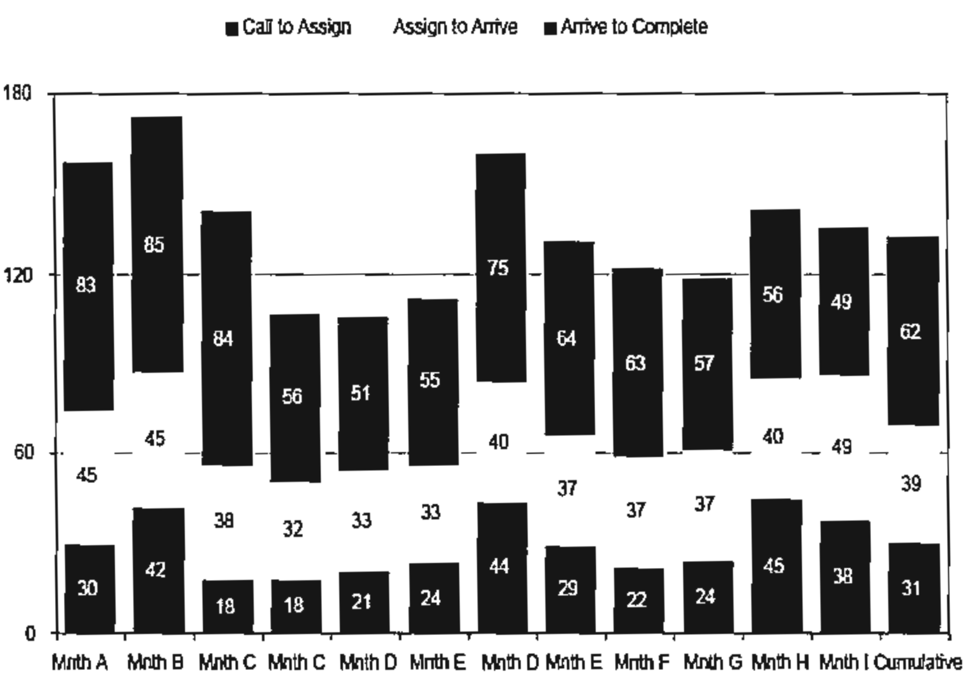


Figure 45—Interruption response by response status

5.10.2.2 Interruption information retrieval methods

Utilities have developed reporting capabilities linked to their outage management system. Reporting methods are developed for company personnel to monitor and retrieve interruption information, which is filtered on a variety of different criteria. The functions being performed, such as worst performing evaluations or circuit lockout reviews, guide the type and amount of information needed.

Figure 46 provides a daily summary by area selected of the total number of events on any given calendar day. The employee can drill down to the details of any of the totals provided by clicking on the numbers.

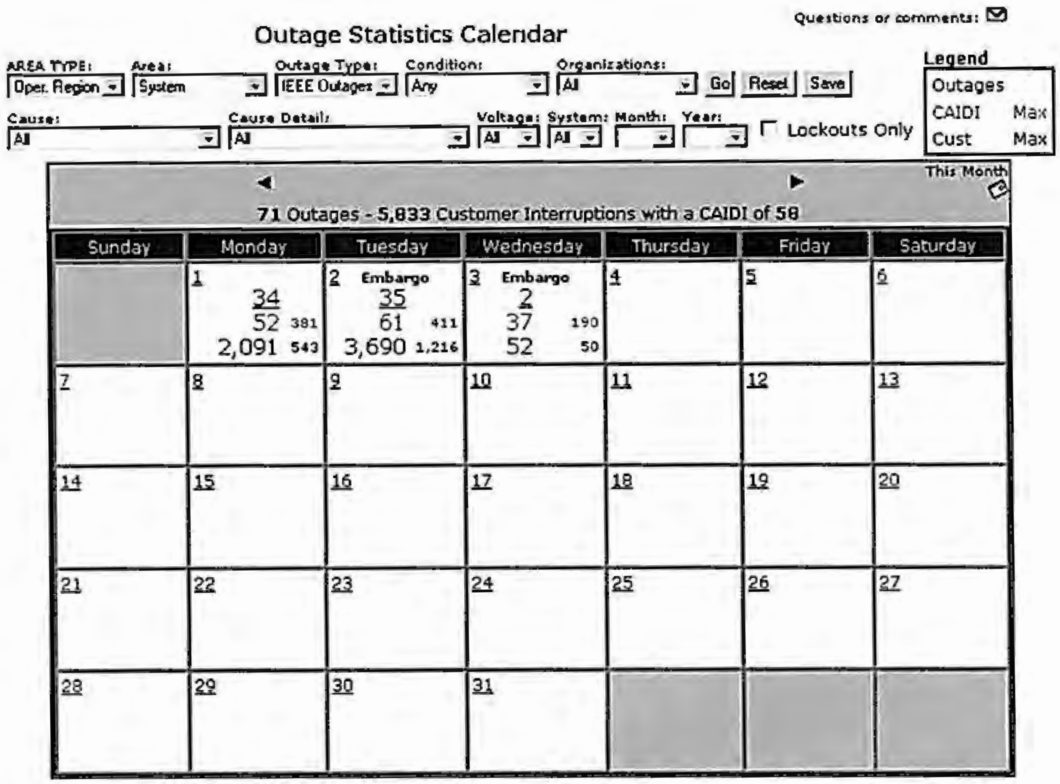
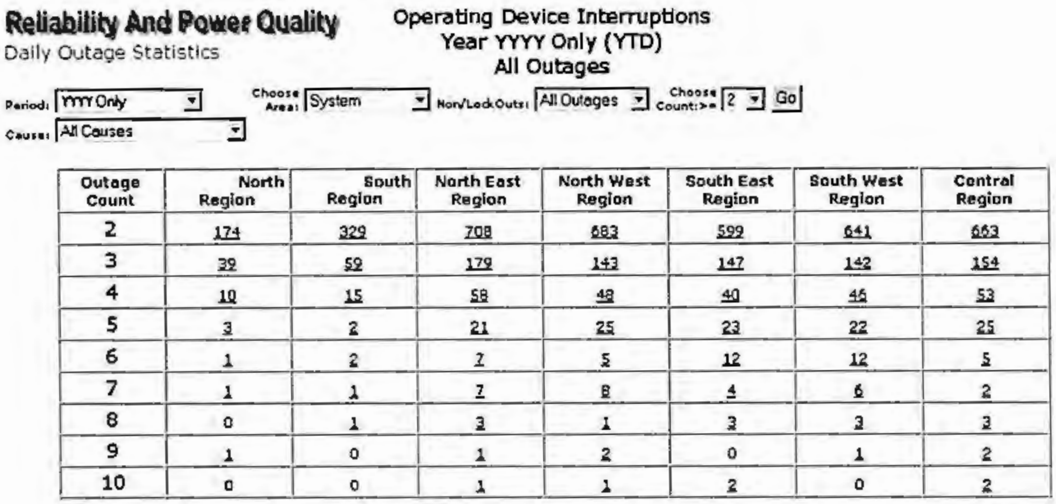


Figure 46—Example of a daily summary of interruptions by area

Figure 47 provides a summary of the number of devices that have experienced multiple outages during the given year for each of the operating areas of the company. Again, the employee can drill down on any of these numbers to obtain a list of devices for further follow up activities.


Reliability And Power Quality
Daily Outage Statistics

Operating Device Interruptions
Year YYYY Only (YTD)
All Outages

Period: YYYY Only | Choose Area: System | Non/LockOuts: All Outages | Choose Count:>= 2 | Go
Cause: All Causes

Outage Count	North Region	South Region	North East Region	North West Region	South East Region	South West Region	Central Region
2	174	329	708	683	599	641	663
3	39	59	179	143	147	142	154
4	10	15	58	48	40	46	53
5	3	2	21	25	23	22	25
6	1	2	7	5	12	12	5
7	1	1	7	8	4	6	2
8	0	1	3	1	3	3	3
9	1	0	1	2	0	1	2
10	0	0	1	1	2	0	2

Figure 47—Example of a summary of device multiple outages

Annex A

(informative)

Breakdown of interruption events by cause

A.1 Interruption events by cause using CI and CMI

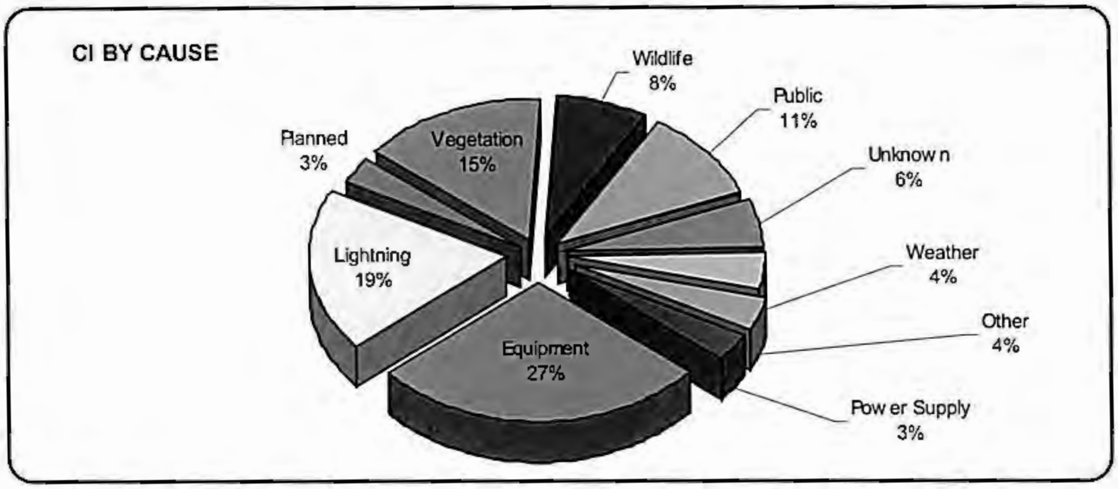


Figure A.1—Customer interruption by cause

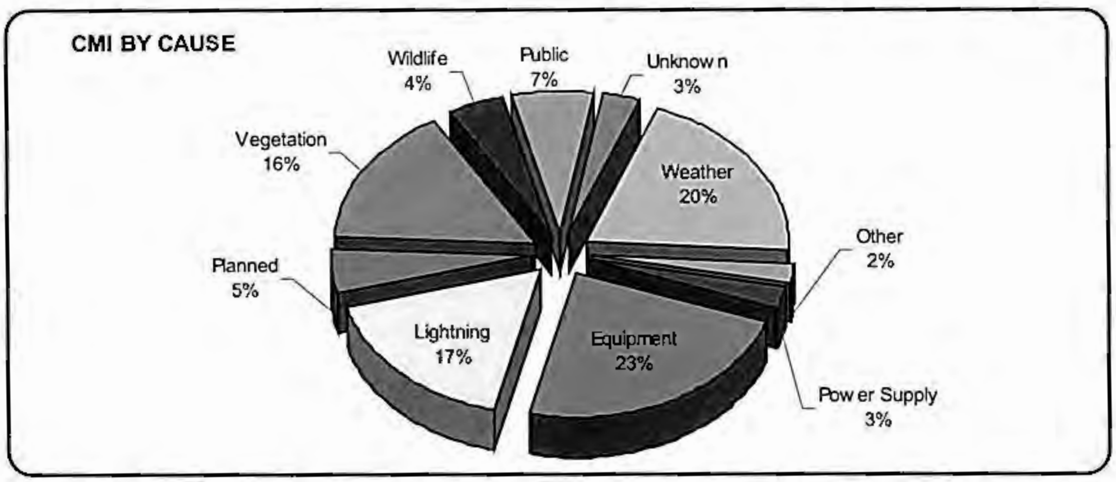


Figure A.2—Customer minutes of interruption by cause

A.2 Comparison of the number of interruption events by cause over a five year period

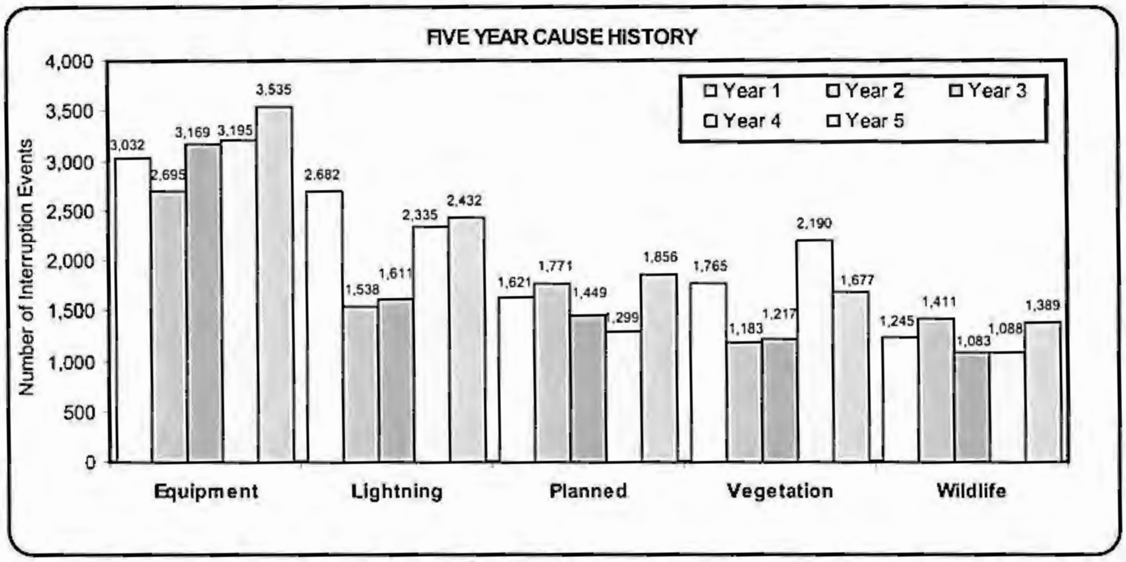


Figure A.3—Five year breakdown by cause

A.3 Examples of wildlife breakdown by specific cause charts

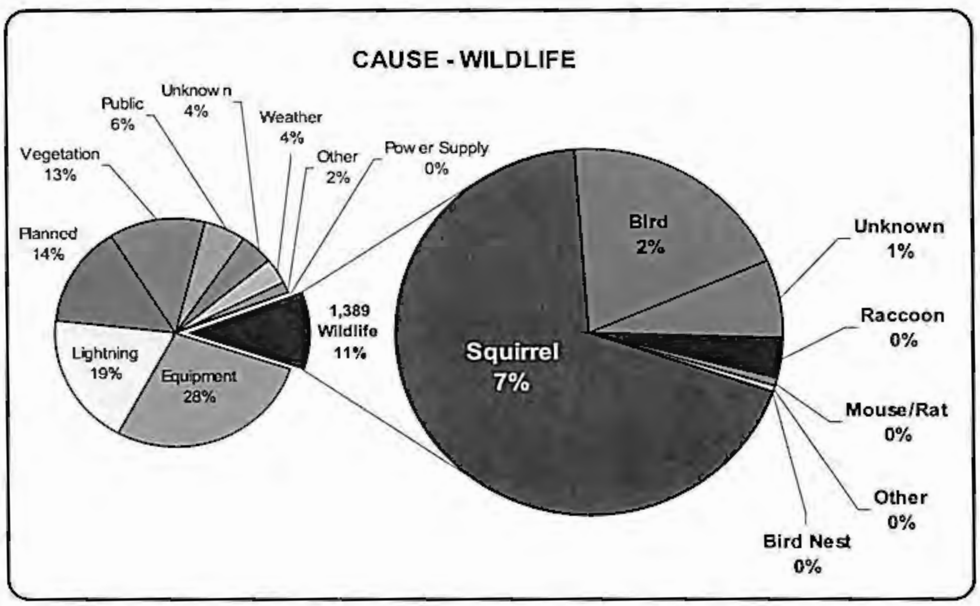


Figure A.4—Wildlife breakdown interruption event by specific cause

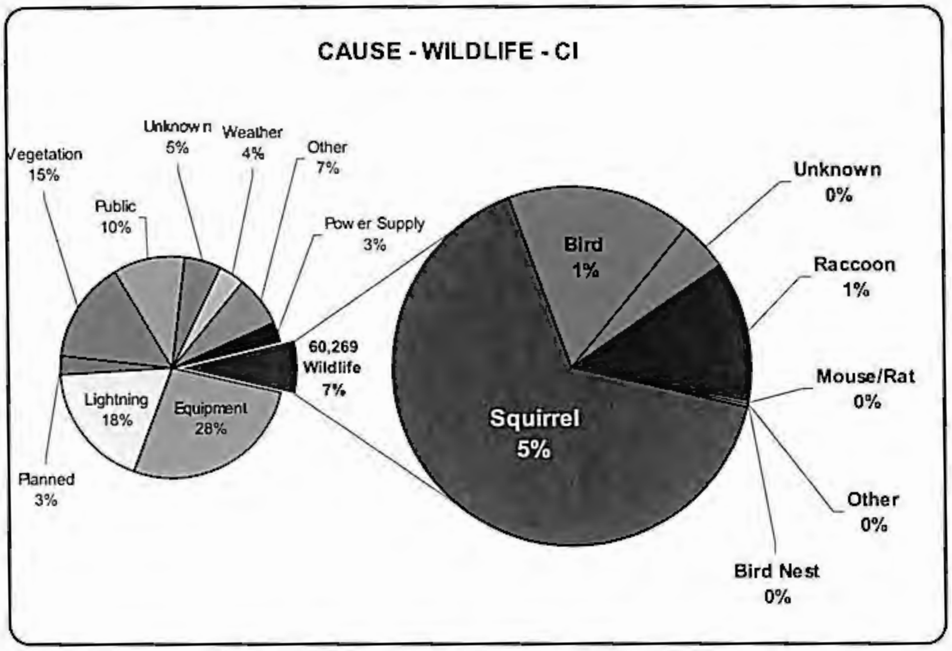


Figure A.5—Wildlife breakdown customer interruptions by specific cause

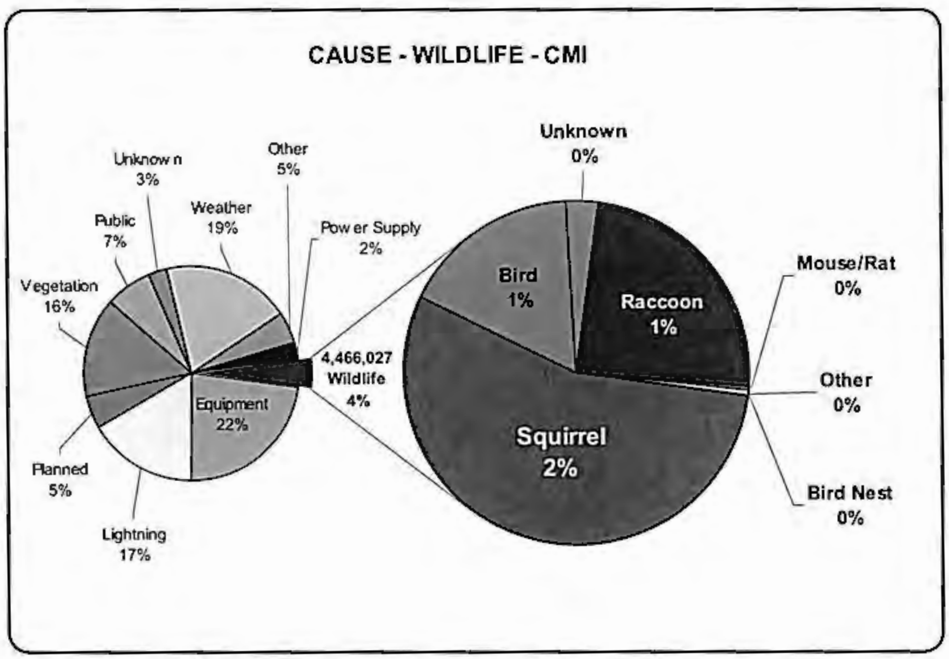


Figure A.6—Wildlife breakdown customer minutes of interruptions by specific cause

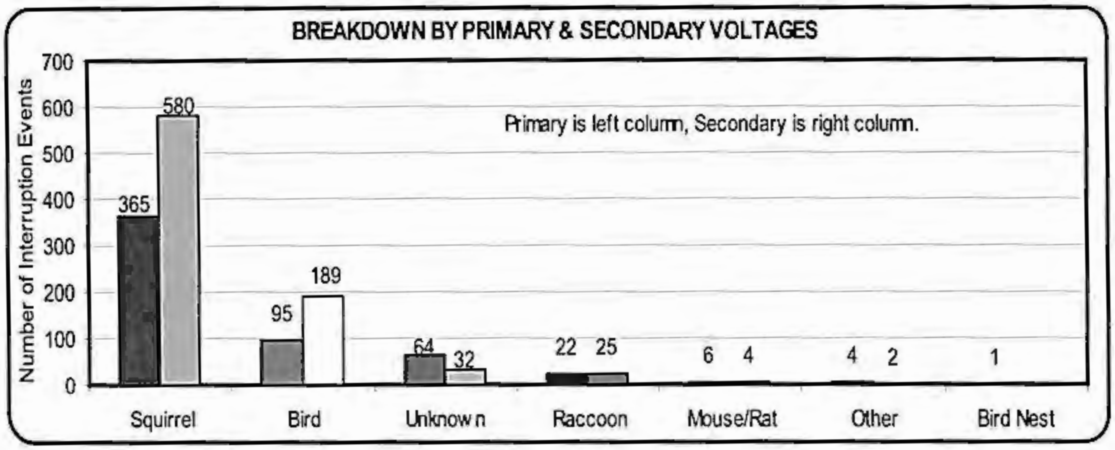


Figure A.7—Primary and secondary breakdown by wildlife type

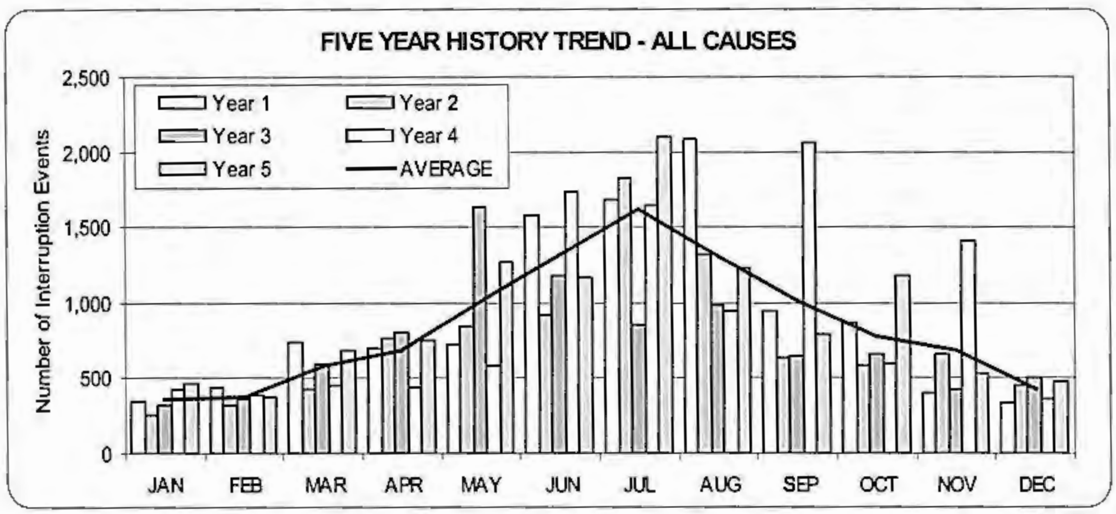


Figure A.8—Interruption events trended over a five year period

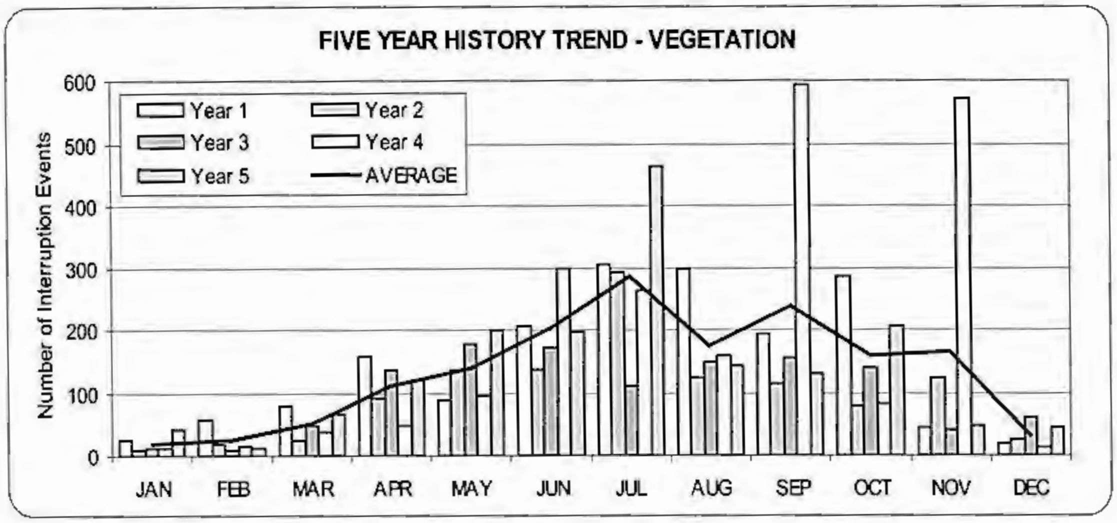


Figure A.9—Vegetation interruption events trended over a five year period

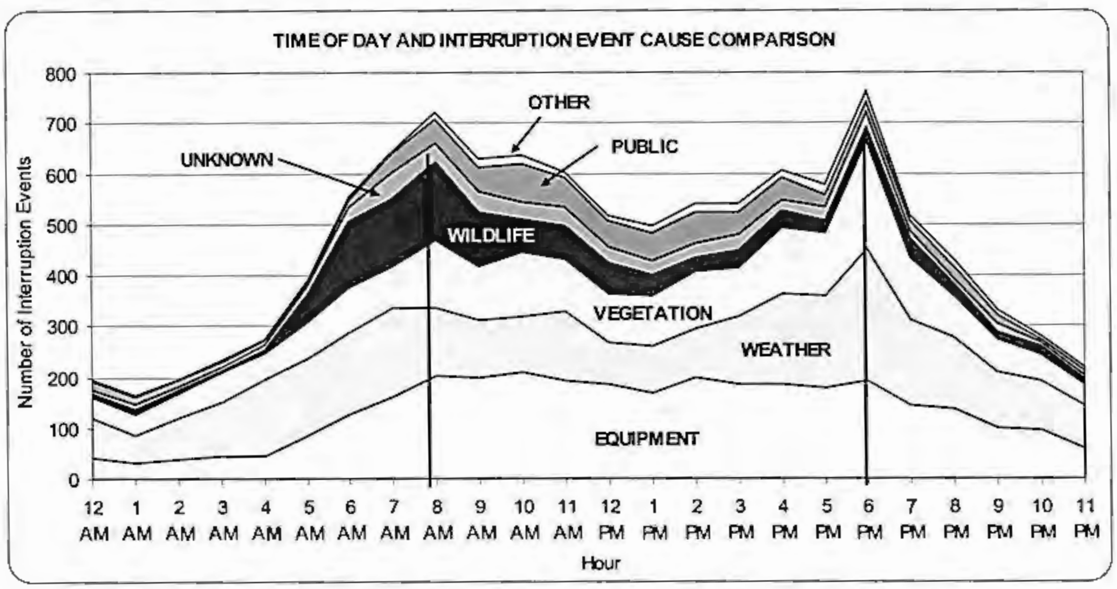


Figure A.10—Cause comparison by hour of day

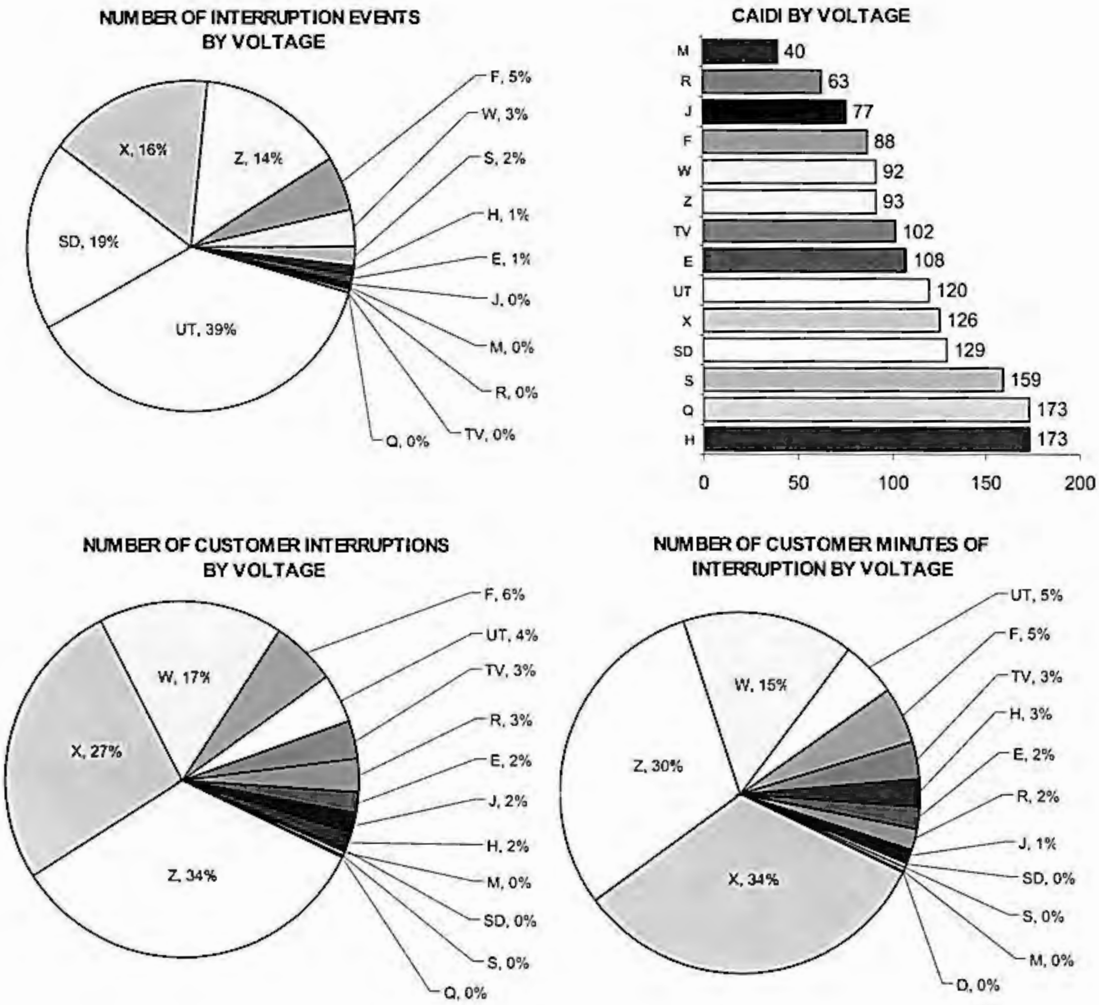


Figure A.11—Interruption events and duration trended by voltage class (letters signify different voltage levels)

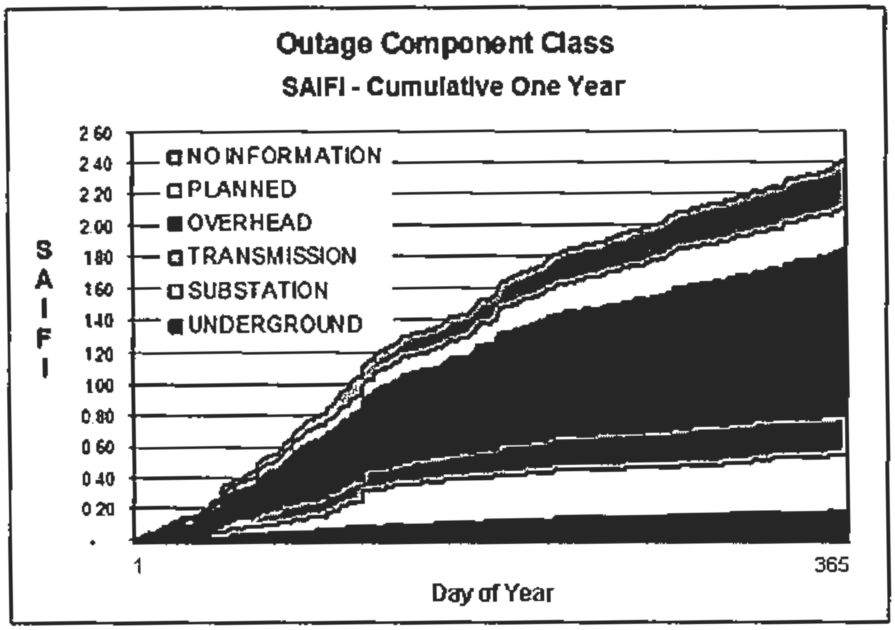


Figure A.12—Contribution to SAIFI by responsible system

Annex B

(informative)

Reliability considerations for protective devices

B.1 Coordination concepts

Substation relay settings may be a method of managing reliability. Consideration for substation relay settings may be appropriate. Use of the instantaneous over-current relay, typically referred to as the fast trip, can result in fewer downstream permanent fuse operations. The breaker operates faster than the fuse, for temporary events beyond the fuse, to keep the fuse from blowing and causing a sustained outage. This type of operation is difficult for troubleshooting efforts since the fault can be in the main line or beyond any of the fuses.

Disabling the fast trip will force the fuse to operate, causing a sustained outage for non-self-clearing temporary events. Any protective device operation should require a troubleshooter to attempt to find the interruption cause. If the trouble spot is found and the source of the interruption event is corrected (with remedial actions as necessary, such as adding wildlife protectors or trimming trees), future interruptions should be reduced. The disadvantage with disabling the fast trip is that customers experience a sustained interruption rather than a momentary interruption for those faults that will uot clear before the fuse blows. In the past, when the majority of the customers' uses were not as sensitive, this trade-off seemed to make sense. However, in recent years as customers' equipment has become more sensitive, a momentary interruption can often have as much impact as a sustained interruption.

If a fast trip is enabled, the utility will encounter multiple momentary interruptions on a breaker. In order to identify the location of the trouble, the fast trip can be disabled to allow a down-line fuse to operate. The utility cau also install fault indicators at strategic points on the line to further help identify the fault location. Once the fault cause is found and the trouble spot corrected, the fast trip can be reset.

Four scenarios are used in Figure B.1, illustrating how the disabling or enabling will impact the customers, in addition to the company's ability to fiud the fault cause.

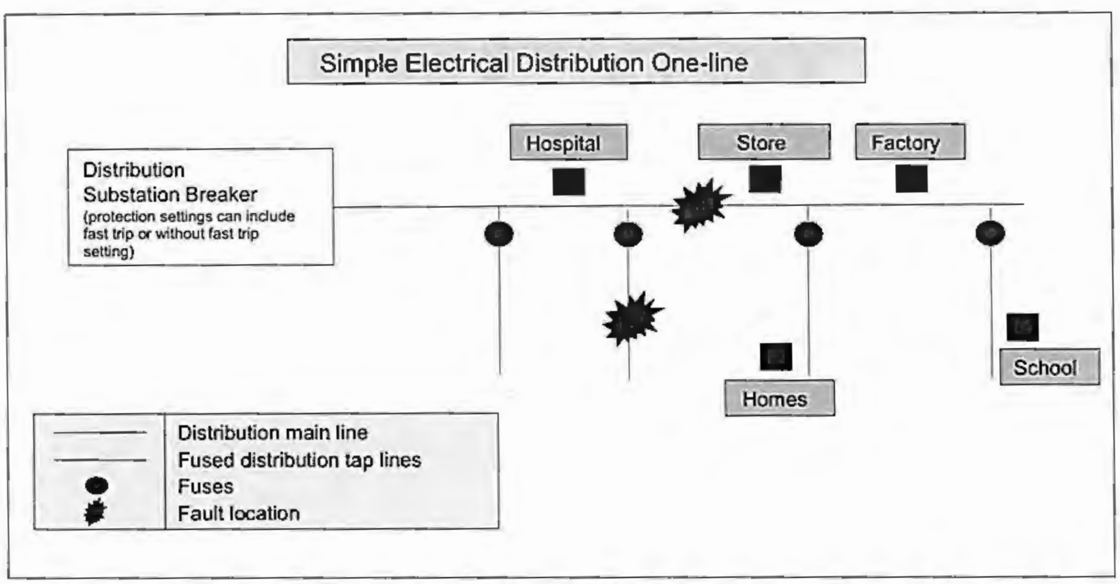


Figure B.1—Simple electrical distribution one-line diagram

For example, viewing Figure B.1, if a permanent fault (line down) or temporary fault (squirrel contact on a service transformer) is experienced, the distribution substation breaker will function as follows:

Fault location 1 or any location along the distribution main:

- Permanent fault
  1) Fast trip enabled
     i) All customers will see fast trip(s), reclose, followed by multiple delay trips, reclose operations, then trip to lockout on the distribution substation breaker. This results in a sustained interruption to all customers until repairs are made.
  2) Fast trip disabled
     i) All customers will see multiple delay trips, reclose operations, then trip to lockout on the distribution substation breaker. This is the same as with the fast trip enabled without the initial fast trip(s).
- Temporary fault
  1) Fast trip enabled
     i) All customers will see fast trip(s), reclose, followed by a delay trip and reclose sequence until the temporary fault condition can clear itself or a breaker lockout occurs (one or more operations).
  2) Fast trip disabled
     i) All customers will see a delay trip and reclose sequence until the temporary fault condition can clear itself or a breaker lockout occurs (at least one less operation than above).

Fault location 2 or any location on each fused distribution tap line:

- Permanent fault
  1) Fast trip enabled
     i) All customers will see a fast trip; reclose sequence (**one** operation) on the distribution substation breaker.
     ii) Customers beyond the fuse will see a fast trip, reclose followed by a sustained interruption (**two** operations) until repairs can be made. The permanent fault will cause the fuse to function which causes an open point at the fuse location.
  2) Fast trip disabled
     i) ***Only*** customers beyond the fused distribution tap line will experience a sustained interruption (**one** operation) until repairs are made.
- Temporary fault
  1) Fast trip enabled
     i) All customers will see a fast trip, reclose sequence (**one** operation) on the distribution substation breaker assuming the temporary fault such as an animal contact clears itself.
  2) Fast trip disabled
     i) ***Only*** customers beyond the fused distribution tap line will experience a sustained interruption until repairs are made.

The advantage to disabling the fast trip is that all customers will experience fewer momentary outages when permanent or temporary faults occur beyond fused distribution tap lines. The disadvantage is that the customers beyond the fuse will experience a sustained interruption for a temporary fault. The general design of a distribution system includes serving a high percentage of customers beyond a fuse installed on a distribution tap line.

B.2 Fuse saving (during storms)

Utilities are sometimes classified as using either a fuse blowing or fuse saving methodology for reliability purposes. When using a fuse blowing scheme, typically an overhead tap fuse would blow for faults due to causes such as lightning or tree contact during storms, rather than giving time for a transient fault to clear by operating the substation circuit breaker momentarily. By not allowing a substation breaker to reclose, customers are saved from unnecessarily experiencing multiple momentary events. A fuse saving scheme will give a transient type of fault an opportunity to clear so that a sustained outage does not occur for any customers.

In order to employ both options, newer type relay schemes allow for multiple or alternate settings on relays, and with the proper communications channels these settings can be changed remotely prior to storms approaching an area when most transient faults occur. Many transient faults can be cleared with one fast trip operation. It is feasible for a utility control operator to switch to a fuse save mode for an entire region or even a service territory prior to a storm approaching by switching a single setting. A utility may want to consider changing the settings "on the fly" to a fuse save mode since trees, and lightning strikes are often transient. This could substantially reduce the number of outages that a utility experiences during a storm, improving reliability and customer satisfaction while at the same time focusing restoration crews on true sustained outages.

This may not be able to be used in all circumstances due to insufficient fault duty and/or coordination issues.

Annex C

(informative)

Reliability performance goals

Reliability data can be used to help establish performance goals for geographic subsidiaries of a utility company based on the utility's ultimate goal. One way of accomplishing this is to perform a multiple regression analysis of potentially important factors affecting reliability performance and then using the resulting relationship to allocate the company's overall goal to its geographic subsidiaries.

Assume a utility is subdivided into geographic subsidiaries called "operating areas" and that the utility has an ultimate SAIFI goal of 0.65. The objective of this analysis is to equably allocate the SAIFI goal to each operating area based on each area's unique characteristics.

The first step in this process is to collect customer interruption (CI) data for each operating area during some period of interest. In addition, potentially important factors that drive customer interruptions in an operating area should be measured. Some of these factors could include quantity of overhead/underground circuit miles, quantity of urban/rural circuit miles, number of overhead/underground transformers, tree density, number of feeder circuits, switchgear capacity, etc.

After collecting this information a regression analysis is performed to identify which, if any, of the independent variables significantly influence the number of customer interruptions experienced in an area. The analysis should employ best practices for regression analysis and consider the effects of outliers, specification error, error distribution, heteroscedasticity, correlated errors, multi-collinearity and variable selection methods.

If a significant model is identified, it can be then used to predict an operating area's customer interruptions based on the independent variables which characterize an area. After adjusting the model to account for the company's overall goal for customer interruptions, the operating area goals can be produced.

To illustrate, one utility found the CI in an operating area could be predicted by the linear relationship shown in Equation (C.1) which corresponded to the actual company SAIFI of 1.14:

$$P = 3714 + 66.32 \times Q + 1.96 \times N \tag{C.1}$$

where

P = Predicted Operating Area Customer Interruptions
Q = Quantity of Urban Circuit Miles in a given Operating Area
N = Number of Overhead Transformers in a given Operating Area

Since the utility's ultimate SAIFI goal was 0.65 this relationship was adjusted by a factor of 0.5712 (0.65/1.14) to obtain an equation describing operating area goals for customer interruptions. By substituting a specific area's independent variable values into the equation, the resulting goal for the area reflects the opportunity for improvement based on that area's specific characteristics. Figure C.1 graphically depicts the results of this analysis.

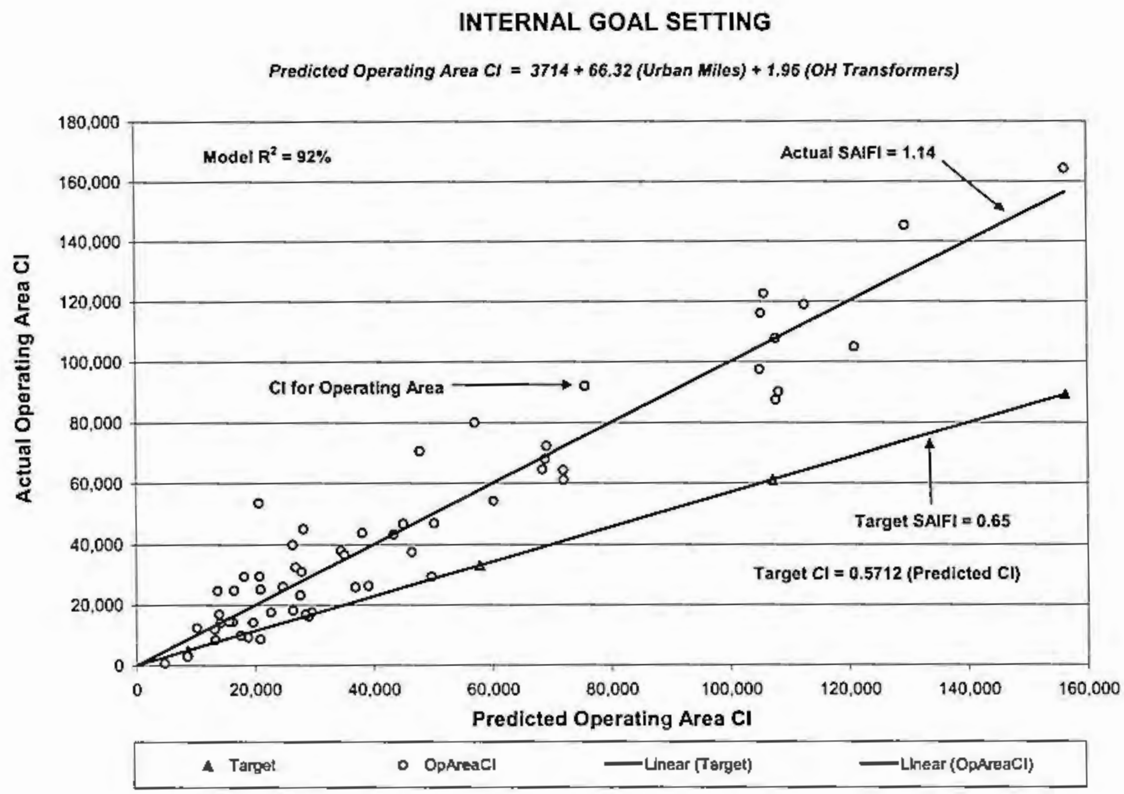


Figure C.1—Internal goal setting example

Annex D

(informative)

Outage information timeline by distribution line

Below is a simple timeline graphic to display outage performance along either a circuit or segment of a line. Blue hash marks denote momentary interruptions, while red hash marks denote sustained interruptions. They are placed along a date timeline. With this graphic one can discern whether there have been substantial changes in either momentary or sustained interruptions through time. Also, it can be observed whether there appears to be any significant seasonality to when those interruptions may take place.

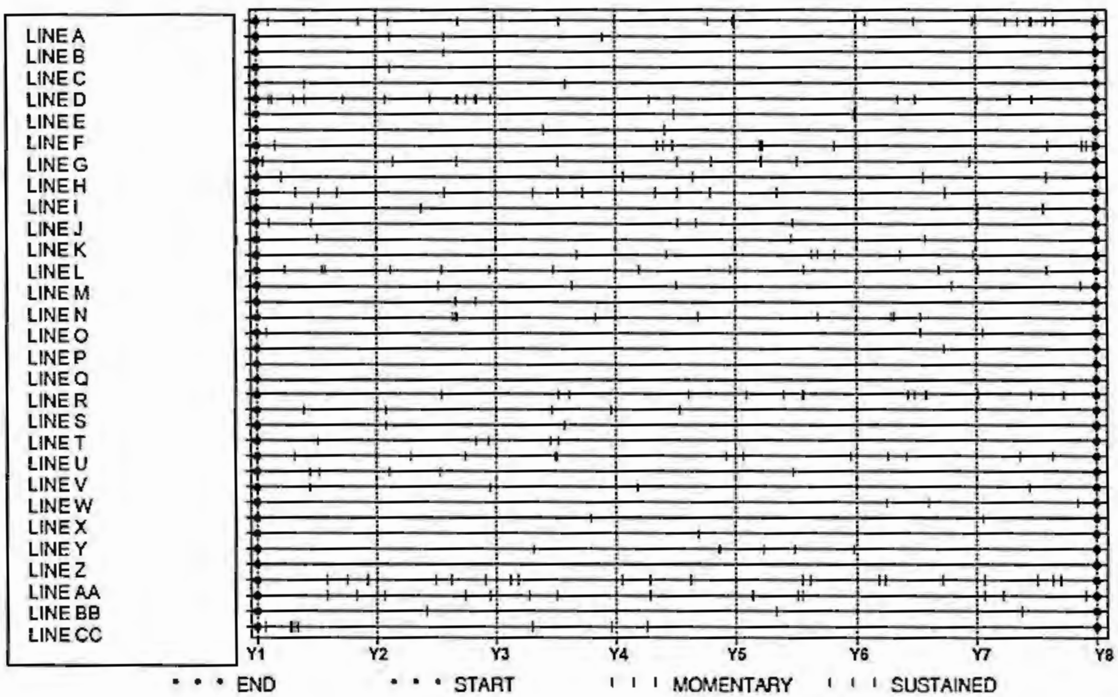


Figure D.1—Outage information by distribution line over time

Annex E

(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.

[B1] Bouford, J. D., and Warren, C. A., "Incrementing Averages, a Methodology for Showing the Impact of OMS Addition on Reliability Indices," Transmission and Distribution Conference and Exhibition, 2005/2006 IEEE PES, pp.1264-1268, 21-24 May 2006.

[B2] Robinson, R., Hall, D., Warren, C., and Werner, V., "Collecting and Categorizing Information Related to Electric power Distribution Interruption Events: Customer Interruption Data Collection within the Electric Power Distribution Industry," IEEE Power Engineering Society General Meeting, pg. 5, 2006.

[B3] Shewhart, W., "Economic Control of Quality of Manufactured Product," American Society for Quality Control, Milwaukee, Wisconsin, 1980.

[B4] Sullivan, M. J., Mercurio, M., and Schellenberg, J., Estimated Value of Service Reliability for Electric Utility Customers in the United States. Lawrence Berkeley National Laboratory Report No. LBNL-2132E, 2009.

[B5] Taylor, L. and Chow, Mo-yuen, "A Novel Approach for Distribution Fault Analysis," *IEEE Tran. Power Delivery*, Vol. 8, No. 4, pp. 1882-1889, Oct. 1993.

[B6] Taylor, L. and Chow, Mo-yuen, "Analysis and Prevention of Animal Caused Faults in Power Distribution Systems," *IEEE Tran. Power Delivery*, Vol. 10, No 2, pp. 995-1001, April 1995.

[B7] Taylor, L. and Chow, Mo-yuen, "Recognizing Animal Caused Faults in Power Distribution Systems Using Artificial Neural Networks," *IEEE Tran. Power Delivery*, Vol. 8, No. 3, pp. 1268-1274, July 1993.

[B8] Taylor, L., Chow, Mo-yuen, and Yee, Sue O., "Data Mining and Analysis of Tree Caused Faults in Power Distribution Systems," Power System Conference and Exposition, PSCE 2006.

[B9] Werner, V., Hall, D., Robinson, R., and Warren, C., "Collecting and Categorizing Information Related to Electric Power Distribution Interruption Events: Data Consistency and Categorization for Benchmarking Surveys," *IEEE Tran. Power Delivery*, vol. 21, no. 1, pp. 48-483, Jan. 2006.

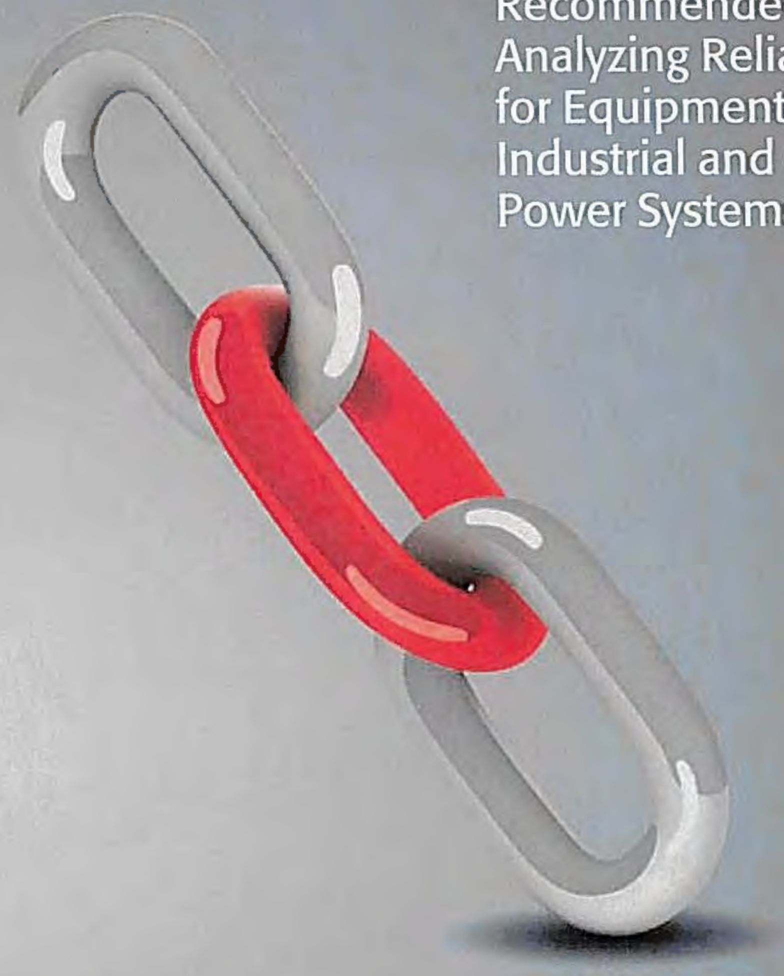
IEEE
standards.ieee.org
Phone: +1 732 981 0060   Fax: +1 732 562 1571

IEEE 3000 STANDARDS COLLECTION®

IEEE 3006 STANDARDS:
POWER SYSTEMS RELIABILITY

IEEE Std 3006.8™-2018

Recommended Practice for Analyzing Reliability Data for Equipment Used in Industrial and Commercial Power Systems



IEEE STANDARDS ASSOCIATION IEEE

IEEE Std 3006.8™-2018

IEEE Recommended Practice for Analyzing Reliability Data for Equipment Used in Industrial and Commercial Power Systems

Sponsor

Technical Books Coordinating Committee
of the
IEEE Industry Applications Society

Approved 27 September 2018

IEEE-SA Standards Board

Abstract: Data supporting the reliability evaluation of existing industrial and commercial power systems are described. This recommended practice is likely to be of greatest value to the power-oriented engineer with limited experience in the area of reliability. It can also be an aid to all engineers responsible for the electrical design of industrial and commercial power systems.

Keywords: availability, IEEE 3006.8™, mean down time (MDT), mean time between failures (MTBF), mean time to maintain (MTTM), mean time to repair (MTTR), reliability analysis, reliability data

---

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

PDF: ISBN 978-1-5044-5029-4 STD23333
Print: ISBN 978-1-5044-5206-9 STDPD23333

Important Notices and Disclaimers Concerning IEEE Standards Documents

IEEE documents are made available for use subject to important notices and legal disclaimers. These notices and disclaimers, or a reference to this page, appear in all standards and may be found under the heading "Important Notices and Disclaimers Concerning IEEE Standards Documents." They can also be obtained on request from IEEE or viewed at http://standards.ieee.org/IPR/disclaimers.html.

Notice and Disclaimer of Liability Concerning the Use of IEEE Standards Documents

IEEE Standards documents (standards, recommended practices, and guides), both full-use and trial-use, are developed within IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association ("IEEE-SA") Standards Board. IEEE ("the Institute") develops its standards through a consensus development process, approved by the American National Standards Institute ("ANSI"), which brings together volunteers representing varied viewpoints and interests to achieve the final product. IEEE Standards are documents developed through scientific, academic, and industry-based technical working groups. Volunteers in IEEE working groups are not necessarily members of the Institute and participate without compensation from IEEE. While IEEE administers the process and establishes rules to promote fairness in the consensus development process, IEEE does not independently evaluate, test, or verify the accuracy of any of the information or the soundness of any judgments contained in its standards.

IEEE Standards do not guarantee or ensure safety, security, health, or environmental protection, or ensure against interference with or from other devices or networks. Implementers and users of IEEE Standards documents are responsible for determining and complying with all appropriate safety, security, environmental, health, and interference protection practices and all applicable laws and regulations.

IEEE does not warrant or represent the accuracy or content of the material contained in its standards, and expressly disclaims all warranties (express, implied and statutory) not included in this or any other document relating to the standard, including, but not limited to, the warranties of: merchantability; fitness for a particular purpose; non-infringement; and quality, accuracy, effectiveness, currency, or completeness of material. In addition, IEEE disclaims any and all conditions relating to: results; and workmanlike effort. IEEE standards documents are supplied "AS IS" and "WITH ALL FAULTS."

Use of an IEEE standard is wholly voluntary. The existence of an IEEE standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard.

In publishing and making its standards available, IEEE is not suggesting or rendering professional or other services for, or on behalf of, any person or entity nor is IEEE undertaking to perform any duty owed by any other person or entity to another. Any person utilizing any IEEE Standards document, should rely upon his or her own independent judgment in the exercise of reasonable care in any given circumstances or, as appropriate, seek the advice of a competent professional in determining the appropriateness of a given IEEE standard.

IN NO EVENT SHALL IEEE BE LIABLE FOR ANY DIRECT, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, OR CONSEQUENTIAL DAMAGES (INCLUDING, BUT NOT LIMITED TO: PROCUREMENT OF SUBSTITUTE GOODS OR SERVICES; LOSS OF USE, DATA, OR PROFITS; OR BUSINESS INTERRUPTION) HOWEVER CAUSED AND ON ANY THEORY OF LIABILITY, WHETHER IN CONTRACT, STRICT LIABILITY, OR TORT (INCLUDING NEGLIGENCE OR OTHERWISE) ARISING IN ANY WAY OUT OF THE PUBLICATION, USE OF, OR RELIANCE UPON ANY STANDARD, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGE AND REGARDLESS OF WHETHER SUCH DAMAGE WAS FORESEEABLE.

Translations

The IEEE consensus development process involves the review of documents in English only. In the event that an IEEE standard is translated, only the English version published by IEEE should be considered the approved IEEE standard.

Official statements

A statement, written or oral, that is not processed in accordance with the IEEE-SA Standards Board Operations Manual shall not be considered or inferred to be the official position of IEEE or any of its committees and shall not be considered to be, or be relied upon as, a formal position of IEEE. At lectures, symposia, seminars, or educational courses, an individual presenting information on IEEE standards shall make it clear that his or her views should be considered the personal views of that individual rather than the formal position of IEEE.

Comments on standards

Comments for revision of IEEE Standards documents are welcome from any interested party, regardless of membership affiliation with IEEE. However, IEEE does not provide consulting information or advice pertaining to IEEE Standards documents. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments. Since IEEE standards represent a consensus of concerned interests, it is important that any responses to comments and questions also receive the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to comments or questions except in those cases where the matter has previously been addressed. For the same reason, IEEE does not respond to interpretation requests. Any person who would like to participate in revisions to an IEEE standard is welcome to join the relevant IEEE working group.

Comments on standards should be submitted to the following address:

Secretary, IEEE-SA Standards Board
445 Hoes Lane
Piscataway, NJ 08854 USA

Laws and regulations

Users of IEEE Standards documents should consult all applicable laws and regulations. Compliance with the provisions of any IEEE Standards document does not imply compliance to any applicable regulatory requirements. Implementers of the standard are responsible for observing or referring to the applicable regulatory requirements. IEEE does not, by the publication of its standards, intend to urge action that is not in compliance with applicable laws, and these documents may not be construed as doing so.

Copyrights

IEEE draft and approved standards are copyrighted by IEEE under U.S. and international copyright laws. They are made available by IEEE and are adopted for a wide variety of both public and private uses. These include both use, by reference, in laws and regulations, and use in private self-regulation, standardization, and the promotion of engineering practices and methods. By making these documents available for use and adoption by public authorities and private users, IEEE does not waive any rights in copyright to the documents.

Photocopies

Subject to payment of the appropriate fee, IEEE will grant users a limited, non-exclusive license to photocopy portions of any individual standard for company or organizational internal use or individual, non-commercial use only. To arrange for payment of licensing fees, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; +1 978 750 8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

Updating of IEEE Standards documents

Users of IEEE Standards documents should be aware that these documents may be superseded at any time by the issuance of new editions or may be amended from time to time through the issuance of amendments, corrigenda, or errata. A current IEEE document at any point in time consists of the current edition of the document together with any amendments, corrigenda, or errata then in effect.

Every IEEE standard is subjected to review at least every ten years. When a document is more than ten years old and has not undergone a revision process, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE standard.

In order to determine whether a given document is the current edition and whether it has been amended through the issuance of amendments, corrigenda, or errata, visit IEEE Xplore at http://ieeexplore.ieee.org/ or contact IEEE at the address listed previously. For more information about the IEEE-SA or IEEE's standards development process, visit the IEEE-SA Website at http://standards.ieee.org.

Errata

Errata, if any, for all IEEE standards can be accessed on the IEEE-SA Website at the following URL: http://standards.ieee.org/findstds/errata/index.html. Users are encouraged to check this URL for errata periodically.

Patents

Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken by the IEEE with respect to the existence or validity of any patent rights in connection therewith. If a patent holder or patent applicant has filed a statement of assurance via an Accepted Letter of Assurance, then the statement is listed on the IEEE-SA Website at http://standards.ieee.org/about/sasb/patcom/patents.html. Letters of Assurance may indicate whether the Submitter is willing or unwilling to grant licenses under patent rights without compensation or under reasonable rates, with reasonable terms and conditions that are demonstrably free of any unfair discrimination to applicants desiring to obtain such licenses.

Essential Patent Claims may exist for which a Letter of Assurance has not been received. The IEEE is not responsible for identifying Essential Patent Claims for which a license may be required, for conducting inquiries into the legal validity or scope of Patents Claims, or determining whether any licensing terms or conditions provided in connection with submission of a Letter of Assurance, if any, or in any licensing agreements are reasonable or non-discriminatory. Users of this standard are expressly advised that determination of the validity of any patent rights, and the risk of infringement of such rights, is entirely their own responsibility. Further information may be obtained from the IEEE Standards Association.

Participants

At the time this IEEE recommended practice was submitted to the IEEE-SA Standards Board for approval, the Power Systems Reliability Working Group of the Technical Books Coordinating Committee of the Industrial and Commercial Power Systems Department of the Industry Applications Society had the following membership:

Robert G. Arno, *Chair*
Neal Dowling, *Vice Chair*

Timothy Coyle
Peyton S. Hale
Masoud Pourali
Robert Schuerger
Michael Simon
Christopher C. Thompson

At the time this IEEE recommended practice was completed, the Power Systems Reliability Working Group had the following membership:

Christopher C. Thompson, *Chair*

Timothy Coyle
Neal Dowling
Peyton S. Hale
Masoud Pourali
Robert Schuerger
Michael Simon

The following members of the individual balloting committee voted on this recommended practice. Balloters may have voted for approval, disapproval, or abstention.

Ali Al Awazi
Robert G. Arno
Louis Barrios
Wallace Binder
Thomas Bishop
Frederick Brockhurst
Gustavo Brunello
Demetrio Bucaneg, Jr.
William Byrd
Paul Cardinal
Dion Caves
Steven Chen
Michael Chirico
Greg Clement
Terry Conrad
Daryld Crow
Glenn Davis
Davide De Luca
Gary Donner
Neal Dowling
H. Landis Floyd
Mietek Glinkowski
Waymon Goch
Edwin Goodwin
Lou Grahor
Randall Groves
Scott Hietpas
Werner Hoelzl
Robert Hoerauf
Gary Hoffman
Richard Holub
Christel Hunter
Gerald Irvine
John Kay
Yuri Khersonsky
Yoonik Kim
Jim Kulchisky
James Lagree
Wei-Jen Lee
Duane Leschert
Albert Livshitz
William Lockley
Daleep Mohla
William Moylan
Jerry Murphy
Daniel Neeser
Dennis Neitzel
Arthur Neubauer
Joe Nims
Gearold O. H. Eidhin
Howard Penrose
Jim Phillips
Masoud Pourali
Iulian Profir
John Rama
James Reilly
John Roach
Tim Rohrer
Ryandi Ryandi
Daniel Sabin
Vincent Saporita
Bartien Sayogo
Robert Schuerger
Kenneth Sedziol
Michael Simon
Jerry Smith
Gary Smullin
Wayne Stec
Thomas Stewart
David Tepen
Wayne Timm
Timothy Unruh
James Van De Ligt
Van Wagner
Keith Waters
Kenneth White
Dean Yager
Jiau Yu
David Zech
Shuhui Zhang
Gaetano Zizzo

When the IEEE-SA Standards Board approved this recommended practice on 27 September 2018, it had the following membership:

Introduction

This introduction is not part of IEEE Std 3006.8-2018, IEEE Recommended Practice for Analyzing Reliability Data for Equipment Used in Industrial and Commercial Power Systems.

IEEE 3000 Standards Collection™

This recommended practice was developed by the Technical Books Coordinating Committee of the Industrial and Commercial Power Systems Department of the Industry Applications Society, as part of a project to repackage the popular IEEE Color Books®. The goal of this project is to speed up the revision process, eliminate duplicate material, and facilitate use of modern publishing and distribution technologies.

When this project is completed, the technical material included in the 13 IEEE Color Books will be included in a series of new standards—the most significant of which will be a new standard, IEEE Std 3000™, IEEE Recommended Practice for the Engineering of Industrial and Commercial Power Systems. The new standard will cover the fundamentals of planning, design, analysis, construction, installation, startup, operation, and maintenance of electrical systems in industrial and commercial facilities. Approximately 60 additional dot standards, organized into the following categories, will provide in-depth treatment of many of the topics introduced by IEEE Std 3000™:

- Power Systems Design (3001 series)
- Power Systems Analysis (3002 series)
- Power Systems Grounding (3003 series)
- Protection and Coordination (3004 series)
- Emergency, Standby Power, and Energy Management Systems (3005 series)
- Power Systems Reliability (3006 series)
- Power Systems Maintenance, Operations, and Safety (3007 series)

In many cases, the material in a dot standard comes from a particular chapter of a particular IEEE Color Book. In other cases, material from several IEEE Color Books has been combined into a new dot standard.

IEEE Std 3006.8™

Knowledge of the reliability of electrical equipment is an important consideration in the design and operation of industrial and commercial power distribution systems. Each of the hundreds of components installed at a facility has an operational signature defined by its failure statistics. When these signatures are analyzed in the context of their relationship in a power system, designers and operators can understand—and more importantly, predict—system performance over time. In response, this recommended practice offers the best facility equipment data currently available. The data that follow represent five decades, millions of dollars, and thousands of hours of labor in the collection of data from more than 300 diverse facilities.

Contents

IEEE Recommended Practice for Analyzing Reliability Data for Equipment Used in Industrial and Commercial Power Systems

1. Overview

1.1 Scope

This recommended practice describes how to analyze reliability data for equipment used in industrial and commercial power systems. Equipment reliability data collected over the years is presented. This is followed by a discussion of key equipment reliability metrics, such as failure rate, downtime to repair in hours per failure, and probability of starting (operating).

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

Historical Reliability Data for IEEE 3006 Standards: Power System Reliability™.[1,2]

IEEE Std 3006.2-2016™, Recommended Practice for Evaluating the Reliability of Existing Industrial and Commercial Power Systems.

3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.[3]

---

[1] The IEEE standards or products referred to in this clause are trademarks of The Institute of Electrical and Electronics Engineers, Inc.
[2] IEEE publications are available from The Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (http://standards.ieee.org/).

For definitions of terms pertaining to power system reliability used in this standard, refer to IEEE Std 3006.5™-2014.

4. Introduction

Knowledge of the reliability of electrical equipment is an important consideration in the design and operation of industrial and commercial power distribution systems. Each of the hundreds of components installed at a facility has an operational signature defined by its failure statistics. When these signatures are analyzed in the context of their relationship in a power system, designers and operators can understand—and more importantly, predict—system performance over time. In response, this recommended practice offers the best facility equipment data currently available. The data that follow represent five decades, millions of dollars, and thousands of hours of labor in the collection of data from more than 300 diverse facilities.

The failure characteristics of individual pieces of electrical equipment can be partially described by the following basic statistics: mean time to repair (MTTR) and mean time between failures (MTBF). From these, most failure statistics can be calculated, including and especially, reliability (r) and inherent availability (a_i). Data on other factors (e.g., cause and type of failures, maintenance procedures, repair method, etc.) are also required to characterize the performance of electrical equipment in service (refer to *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 1 and page 61 for more information).

Availability is a key measure of facility performance. Many facilities operate for long periods of time, providing power to perform critical functions. Balancing the cost of design, construction, and maintenance against the requirement for continuous and reliable operation is of the utmost importance. Understanding both component-level and system-level failure statistics is essential to achieving this balance.

The data in this recommended practice are used to model power system performance. The analytical models required for estimating power system performance are presented in IEEE Std 3006.3™-2017 [B21], IEEE Std 3006.5™-2014, and IEEE Std 3006.9™-2013 [B23].

The recommended practice is divided into three parts, which together cover data collection programs spanning more than 45 years. Each part consists of a large collection of equipment reliability and availability statistics.

Part 1 includes data from two major collection efforts conducted by the U.S. Army Corps of Engineers Power Reliability Enhancement Program (USACE-PREP). The 1994 data collection program was extensive, including information for many types of commercial facilities within the United States. The 2005 program replicated and expanded upon the 1994 program, respecting its standards for data integrity. Together, these efforts created the most comprehensive facility equipment reliability database in existence.

Part 2 is a collection of equipment surveys conducted between 1976 and 1994. The resolution is remarkable, as it specifically divulges cause of failure, a valuable piece of knowledge for facility managers.

Part 3 is a collection of equipment surveys conducted before 1976. The data in this collection reveal detail about failure modes, time of failure discovery, and how failures were repaired following discovery. The data also give failure data for utility providers in a variety of configurations and voltage classes.

Each of the three parts complements the others, providing focused data to key indicators of equipment performance. Details of the survey data (Part 2 and Part 3) are unavailable to statistically merge with the data collected in Part 1; the raw individual component information from the data collection has been lost over time.

[3]*IEEE Standards Dictionary Online* is available at: http://dictionary.ieee.org.

An additional archive of data can be found in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*. This document contains information according to Table 1.

Table 1—Historical reliability data for IEEE 3006 Standards reference guide

Electrical equipment types	*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*
Motors, > 50 hp (37.3 kW)	pages 1, 61, 124
Motor starters	pages 1, 61
Generators	pages 1, 61, 187
Circuit breakers	pages 1, 61, 161, 170, 266
Disconnect switches	pages 1, 61
Bus duct	pages 1, 61
Switchgear bus, insulated	pages 1, 61, 100
Open wire	pages 1, 61
Cable	pages 1, 61, 151
Transmission lines, 230 kV and above	page 221
Electric utility power supplies	pages 1, 61, 95

The IEEE Industry Applications Society (IAS) has also conducted surveys on the reliability of electrical equipment in industrial and commercial installations (see Aquilino [B4], Dickinson [B6], IEEE Committee Reports [B11], [B12], [B13], [B29], and O'Donnell [B28], [B30]).

5. Part 1: Mechanical and electrical equipment data, 1994 and 2005

5.1 Database development

5.1.1 Summary of contents

The data presented in this section is the culmination of more than 50 000 h of effort to collect operational and maintenance data on 280 power generation, power distribution, and HVAC equipment items, including generators, switchgear assemblies, cables, boilers, piping, valves, and chillers.

A database was developed to assist technical staff in organizing, tracking, analyzing, and reporting all of the technical and contact information during the execution of these projects. The database contains:

a) Contact and site records. These records ensure data is unique by keeping accurate accounts of what information has been accepted and what has been rejected from different sites. These records also allow data analysts the opportunity to follow-up with facility managers to complete or update data records. Nearly 400 sites have been contacted or surveyed to provide data; approximately 300 have provided data that meets the standards for inclusion in the database.

b) Equipment records. These include all of the specific reliability and maintainability information for each component. The database contains information for 280 component types. This includes some 370 000 individual pieces of equipment, 900 000 failure and maintenance event records, and 1 900 000 unit-years of equipment operation. In many cases, records also contain more detailed information, such as failure mode, cause of failure, manufacturers, operating modes, etc.

A comprehensive database system allowed the program to record site information, prioritize site visits, collect and organize data, input and verify data, summarize and analyze data, and produce reports. The output record generator contains several canned reports designed for data summary and availability calculations. Some of the reports are designed to allow the user the flexibility to select a multitude of query topics.

The database software and structure has evolved as the database has grown. The current version is contained in a common software package with a user-friendly front-end graphical user interface. Recent design changes allowed new data to be automatically uploaded, reducing manual labor and increasing accuracy.

5.1.2 Data collection

Contacts were the key to the success of this program. The cooperation and support of the people involved from the many facilities is demonstrated in the quality of data received to support the data collection.

A concerted effort was employed to develop an extensive contact database using manufacturers, facilities, societies, and locations of any potential data contributor utilizing key electrical, mechanical, and control components. The collection teams sought manufacturers for contacts as well as warranty information, 25 of which participated. A total of 25 professional societies were also contacted, including:

a) American Gas Association

b) National Association of Power Engineers

c) American Society of Mechanical Engineers

d) Association of Physical Plant Administrators

e) Association of Energy Engineers

The final list of sites includes universities, government facilities, prisons, utilities, office buildings, and other types of facilities. Specifics of these contributors are withheld to protect the confidentiality of the sources.

Building and managing the database requires a broad focus, looking into how each additional site contributes to the database as a whole. In order to collect statistically valid data it was important that a stratified survey of different facility categories, applications, and operating conditions be conducted. Guidelines were developed to assist in the selection of potential sites that vary in (a) degree of maintenance, (b) facility type, (c) component size, and (d) equipment age.

Collecting diversified data was critical to covering the spectrum of how equipment may operate and fail. To locate sites with equipment and data collection policies that conform to the standards of the database, surveys were first issued to hundreds of candidate facilities. Those that responded with potential for inclusion were visited by the data collection team. The team then copied the data, to be later pushed through the rigorous quality assurance process. The procedure for conducting the survey is given in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 109. Information on the determination and analysis of reliability studies is presented in IEEE Std 500™-1984 [B18].

5.1.3 Data summarization and classification

As with every data collection program, there are varying degrees of completeness in the data gathered. Some data sources had complete records and could give statistics on operational characteristics on every piece of equipment from the installation date through the collection date. More often, the only items tracked were major items, such as cooling towers and generators. Other problems included incomplete or non-current versions of the equipment drawings.

It became important to categorize the different levels of data completeness to ensure that the final data collection included fair data representation for each component. In other words, it is important to avoid a bias stemming from record quality. To quantify this data completion (or quality) index, the collection team identified these four levels:

a) *Perfect data:* Data needed for a valid, complete reliability study, including a parts list, failure history data with time-to-failure statistics, parts description data, operational periods, and five continuous years of recorded data. No engineering judgment or data extrapolation is required. The USACE-PREP equipment record database is composed of 10% to 20% of this type of data.

b) *Imperfect data:* Data without serious flaws, but the data collection process demanded additional time to ensure useful information was gathered. Examples include parts list determined by inspection, incomplete drawings, or less than five years of data. The USACE-PREP equipment record database contains 35% to 40% of this type of data.

c) *Verbal/inspection data:* Data with serious gaps that required additional documentation and verification prior to its inclusion in the database. Items included were typically major items, such as generator sets and boilers. Senior maintenance personnel were interviewed to extract the necessary information to fill the data gaps. These interviews were used as support documentation of recorded data, not as data source information. About 25% of this type of data exists in the USACE-PREP equipment record database.

d) *Soft data:* Data that relied on the memories of experienced maintenance personnel from the participating facility; it was often extracted from log books containing maintenance personnel entries, filing cabinets with work order forms, and repair records when outside repair support was needed. Engineering judgment was often used to determine numerous performance parameters. This type of data was the most difficult and time consuming to summarize, and was only used when other data sources were unavailable and when it could be sufficiently completed to meet the input standards. The USACE-PREP equipment record database is composed of 10% to 15% of this type of data.

These levels helped determine the effort required to identify and categorize the components at the site. Engineers prepared all candidate data for analysis through a process called *summarization*. The database requires all information to be imported in correct and consistent format. Engineers assemble all known data for a subject component in tables, including nameplate information, such as make, model, serial number, install/removal date, etc., and failure and maintenance event information, such as date of incident, outage duration, cause of event, type of event, etc. Engineers purged data for other types of equipment outside of the database scope.

5.1.4 Maintenance policy

One objective of the data collection effort was to minimize the effects of maintenance policies and procedures on the calculated availability values by collecting data from a variety of locations having various maintenance policies. The database team developed a code to categorize each facility's maintenance policies and procedures into one of three levels:

a) Code 1: Above average maintenance policy. The facility not only followed a scheduled, preventive maintenance policy that was equivalent or similar to the manufacturer's suggested policy, but also went beyond it, such as using redundant units, specialized equipment tests (thermograph, vibration analysis, oil analysis), complete spare parts kits for equipment, and so on. The USACE-PREP equipment database is composed of 25% of this type of data.

b) Code 2: Average maintenance policy. The facility used either in-house maintenance crews performing scheduled, preventative maintenance according to the equipment manufacturer's suggested preventive maintenance schedule, or a combination of in-house maintenance crews and outside contractors. In both cases, it was verified that they did actually follow a fairly rigid schedule. The USACE-PREP equipment database is composed of 58% of this type of data.

c) Code 3: Below average maintenance policy. The facility's actual policy was slightly lower than average. It may have instituted a scheduled maintenance policy but not followed it, or it may have had no maintenance policy. Symptoms such as leaky valves with rags tied around them, dirty air filters, squeaky bearings, loose belts, and lax general housekeeping because of unavailable labor were typical signs that maintenance policies were less than desirable. The USACE-PREP equipment database is composed of 17% of this type of data.

Each location was then compared to each other and to the average maintenance policy. Overall, the facilities that the collection teams visited practiced an average level of maintenance; that is, they adhered to the manufacturer's recommended maintenance policies. The team looked at approximately the same number of facilities that had below average maintenance policies as those facilities that had an above average maintenance policy.

5.1.5 Analysis and inclusion

Engineers used test statistics (goodness-of-fit, Weibull) to compare candidate data to established populations of reliability data. Significant outliers warranted a review of the data set being considered. If the new data set was both an outlier and showed suspicious site data (e.g., data gaps, mistakes) the data set was rejected. A statistical outlier alone was not a sufficient reason to reject candidate data.

Following the analysis, engineers made accept/reject decisions for every candidate data set. A computer algorithm processed all accepted data, verifying formatting, data types, and other information. Engineers reviewed an output file for each submission, confirming that data was incorporated into the database as expected.

5.2 Results

5.2.1 USACE-PREP equipment reliability database

The final USACE-PREP database includes the 280 different components. A hierarchical structure provides the analyst with options to use a specific type of component or data for a general category of components. As an example, the *category* of Accumulator comprises two *classes* (pressurized and unpressurized). Reliability data are presented for each class and for the entire category of Accumulators.

Some categories of equipment are more complete than others. Though not a perfect proxy, unit-years can be used to interpret the confidence in a data point. A few components have less than 10 unit-years of information available; many have more than 10 000. When using information from the database, the analyst may opt to use a data point for a category of equipment, which may be a more reliable statistic than a data point for a specific class.

Table 2 displays the average failure and maintenance statistics of the data collection described in Part 1.

Table 2—USACE-PREP equipment reliability database

Category			Class	Unit-years	Failures	Failure rate (failures/year)	MTBF (hours)	MTTR (hours)	MTTM (hours)	MDT (hours)
Accumulator				**1463.2**	**10**	**0.006 834 233**	**1 281 782**	**7.80**	**0.94**	**0.98**
	Pressurized	H01-100	Accumulator, pressurized	1072.8	7	0.006 525 131	1 342 502	10.29	0.96	1.01
	Unpressurized	H01-200	Accumulator, unpressurized	390.4	3	0.007 683 510	1 140 104	2.00	0.33	0.42
Air compressor				5124.5	1592	0.310 662 877	28 198	12.20	1.55	4.24
	Electric	H02-100	Air compressor, electric	4534.6	1492	0.329 029 093	26 624	11.80	1.48	4.16
	Fuel	H02-200	Air compressor, fuel	590.0	100	0.169 499 396	51 682	17.45	2.72	5.71
Air conditioner	All types	H03-000	Air conditioner	4947.4	781	0.157 860 257	55 492	5.95	1.59	2.63
Air dryer	All types	H04-000	Air dryer, all types	2307.2	170	0.073 681 948	118 889	9.11	1.44	5.36
Air handling unit				12 173.7	2650	0.217 681 964	40 242	5.06	1.99	3.27
	Humid			379.1	68	0.179 375 438	48 836	2.55	2.53	3.21
		H05-110[a]	Air handling unit, humid, pan humid, w/o drive	25.0	0	0.027 695 536	429 882	0.00	0.00	0.00
		H05-130	Air handling unit, humid, pan humid, with drive	212.8	30	0.140 975 629	62 138	3.02	2.73	2.94
		H05-120[a]	Air handling unit, humid, spray humid, w/o drive	38.1	0	0.018205276	653 976	0.00	0.00	0.00
		H05-140	Air handling unit, humid, spray humid, with drive	103.2	38	0.368 256 160	23 788	2.27	1.59	4.31
	Multizone system	H05-310	Air handling unit, multizone system, packaged	1103.7	448	0.405 891 785	21 582	6.18	4.34	9.97
	Non-humid			10 690.9	2134	0.199 609 243	43 886	4.75	1.67	2.38
		H05-210	Air handling unit, non-humid, without drive	7821.1	1734	0.221 709 225	39 511	4.95	1.88	2.40
		H05-220	Air handling unit, non-humid, with drive	2869.8	400	0.139 380 939	62 849	4.18	1.51	2.36
Air separator	All types	H06-000	Air separator, all types	84.7	9	0.106 272 848	82 429	6.31	0.88	3.35
Surge arrester	Surge and lightning	E01-000	Surge arrester, surge and lightning	1863.4	12	0.006 439 803	1 360 290	9.50	12.28	11.66
Battery	Rechargeable			13 228.7	121	0.009 146 782	957 714	13.40	0.16	0.45
		E02-110	Battery, gel cell-sealed	3106.8	53	0.017 059 514	513 496	2.00	0.13	0.15
		E02-120	Battery, lead acid	5022.6	65	0.012 941 467	676 894	24.08	0.25	4.31
		E02-130	Battery, nickel-cadmium	5099.3	3	0.000 588 315	14 889 985	10.33	0.16	0.16

Blower				4307.0	239	0.055 490 708	157 864	9.44	0.17	0.63
	Without drive	H07-100	Blower, without drive	3947.4	189	0.047 880 115	182 957	10.75	0.17	0.32
	With drive	H07-200	Blower with drive	359.7	50	0.139 016 903	63 014	3.79	1.04	24.95
Boiler				5125.6	2190	0.427 265 681	20 502	17.69	6.61	8.72
	Hot water	H08-100	Boiler, hot water	2566.6	688	0.268 055 191	32 680	3.94	6.35	6.89
	Steam			2559.0	1502	0.586 952 425	14 925	24.40	6.70	9.37
		H08-210	Boiler, steam, high pressure, > 103.4 kPa (15 psig)	942.7	781	0.828 434 093	10 574	39.77	5.52	6.84
		H08-220	Boiler, steam, low pressure, ≤ 103.4 kPa (15 psig)	1616.2	721	0.446 097 568	19 637	13.25	48.03	40.86
Bus duct or busway	All types	E03-000	Bus duct or busway, all types, per 30.5 m (100 ft)	2462.3	143	0.058 075 621	150 838	1.65	1.08	1.26
Cabinet heaters	Forced air flow			14 053.8	64	0.004 553 920	1 923 618	3.10	1.23	1.56
		E04-100	Cabinet heaters, forced air flow, steam or hot water	13 931.1	64	0.004 594 025	1 906 825	3.10	1.23	1.56
		E04-200[a]	Cabinet heaters, forced air flow, electric	122.7	0	0.005 649 689	2 107 341	0.00	0.67	0.67
Cable				736 799.6	1366	0.001 853 964	4 725 011	5.59	4.34	4.43
	AC			698 824.2	924	0.001 322 221	6 625 216	7.29	4.35	4.50
		E06-111	Cable, ac, 0 V to 600 V, above ground, in conduit, per 305 m (1000 ft)	29 442.9	2	0.000 067 928	28 959 932	8.00	13.06	13.01
		E06-112[a]	Cable, ac, 0 V to 600 V, above ground, in trays, per 305 m (1000 ft)	15.9	0	0.043 545 391	273 412			
		E06-113	Cable, ac, 0 V to 600 V, above ground, no conduit, per 305 m (1000 ft)	33 286.3	4	0.000 120 170	72 896 904	2.50	0.05	0.08
		E06-121	Cable, ac, 0 V to 600 V, below ground, in duct, per 305 m (1000 ft)	40 000.4	5	0.000 124 999	70 080 730	16.40	0.73	2.79
		E06-122	Cable, ac, 0 V to 600 V, below ground, in conduit, per 305 m (1000 ft)	24 426.8	49	0.002 005 991	4 366 919	11.22	87.71	28.22
		E06-123	Cable, ac, 0 V to 600 V, below ground, insulated, per 305 m (1000 ft)	3095.3	80	0.025 845 534	338 937	7.60		7.60

		E06-211	Cable, ac, 601 kV to 15 kV, above ground, in conduit, per 305 m (1000 ft)	523 356.6	281	0.000 536 919	16 315 315	8.56	40.51	16.11
		E06-212[a]	Cable, ac, 601 kV to 15 kV, Above ground, in trays, per 305 m (1000 ft)	180.1	0	0.003 849 060	3 093 176			
		E06-214	Cable, ac, 601 kV to 15 kV, above ground, in trays, in conduit, per 305 m (1000 ft)	2646.0	2	0.000 755 852	11 589 564	4.00		4.00
		E06-221	Cable, ac, 601 kV to 15 kV, below ground, in conduit, per 305 m (1000 ft)	19 525.5	46	0.002 355 896	3 718 331	15.70	211.43	41.55
		E06-222	Cable, ac, 601 kV to 15 kV, below ground, in duct, per 305 m (1000 ft)	78.1	1	0.012 799 383	684 408			
		E06-223	Cable, ac, 601 kV to 15 kV, below ground, insulated, per 305 m (1000 ft)	22 770.3	454	0.019 938 292	439 356	5.13	3.97	4.01
	Aerial			37 500.3	439	0.011 706 565	748 298	2.03	0.35	1.91
		E07-200	Cable, aerial, > 15 kV, per 1.6 km (1 mile)	30 884.9	127	0.004 112 048	2 130 325	2.54	0.35	2.08
		E07-100	Cable, aerial, 0 kV to 15 kV, per 1.6 km (1 mile)	6615.5	312	0.047 162 173	185 742	1.82		1.82
	DC	E08-100	Cable, dc, insulated, per 305 m (1000 ft)	475.1	3	0.006 313 969	1 387 400	2.00		2.00
Cable connection	Underground	E05-100	Cable connection, underground, duct, ≤ 600 V	21 574.5	8	0.000 370 808	23 624 073	0.75		0.75
Capacitor bank	All types	E10-000	Capacitor/capacitor bank, all types	2041.1	104	0.050 951 857	171 927	2.37	4.27	3.13
Charger	Battery	E11-000	Charger, battery	666.0	26	0.039 040 966	224 380	7.46	0.72	2.29
Chiller				3607.7	1283	0.355 626 726	24 633	8.57	1.86	3.33
	Absorption	H10-100	Chiller, absorption	587.7	93	0.158 231 093	55 362	11.40	0.68	0.72
	Centrifugal			1054.5	529	0.501 674 408	17 462	7.73	11.29	24.68
		H10-210	Chiller, centrifugal, ≤ 600 tons (2110 kW)	152.1	298	1.959 149 120	4471	5.75	29.58	140.30
		H10-230	Chiller, centrifugal, > 1000 tons (3517 kW)	242.9	152	0.625 733 105	14 000	9.23	35.17	35.44

		H10-220	Chiller, centrifugal, 600 tons to 1000 tons (2110 kW to 3517 kW)	659.4	79	0.119 797 371	73 123	11.81	5.28	5.51
	Reciprocating			1193.5	192	0.160 868 248	54 455	10.77	1.65	2.21
		H10-321	Chiller, reciprocating, closed, with drive, 50 tons to 200 tons (176 kW to 703 kW)	881.8	139	0.157 633 096	55 572	11.11	1.53	2.06
		H10-331	Chiller, reciprocating, open, w/o drive, 50 tons to 200 tons (176 kW to 703 kW)	285.7	53	0.185 495 934	47 225	10.02	2.98	3.80
		H10-311[a]	Chiller, reciprocating, with drive, < 50 tons (176 kW)	26.0	0	0.026 651 082	446 729		1.00	1.00
	Rotary			122.5	15	0.122 477 741	71 523	7.33	8.47	9.47
		H10-420	Chiller, rotary, < 600 tons (2110 kW)	32.0	1	0.031 244 650	280 368	1.00	1.63	1.60
		H10-410	Chiller, rotary, 600 tons to 1000 tons (2110 kW to 3517 kW)	90.5	14	0.154 754 694	56 606	8.60	8.74	9.79
	Screw			649.5	454	0.698 994 807	12 532	7.83	8.12	10.69
		H10-510	Chiller, screw, ≤ 300 tons (1055 kW)	499.0	380	0.761 497 960	11 504	5.37	27.44	15.71
		H10-520	Chiller, screw, > 300 tons (1055 kW)	150.5	74	0.491 734 634	17 814	23.24	6.37	7.97
Circuit breaker				180 935.2	1437	0.007 942 070	1 102 987	15.11	7.99	11.33
	Air			9012.4	93	0.010 319 132	848 909	11.65	73.27	60.16
		E12-111	Circuit breaker, air, 3-phase, > 600 V, > 600 A, normally closed (NC)	8885.8	90	0.010 128 467	864 889	11.65	73.27	60.16
		E12-112	Circuit breaker, air, 3-phase, > 600 V, > 600 A, normally open (NO)	126.5	3	0.023 707 970	369 496			
	Fixed (includes molded case)			150 305.9	10	0.000 066 531	31 667 972	25.36	8.29	9.74
		E12-211	Circuit breaker, fixed (includes molded case), 3-phase, ≤ 600 V, ≤ 600 A, normally closed (NC)	34 569.2	4	0.000 115 710	75 706 529	23.25	3.09	9.64

		E12-212	Circuit breaker, fixed (includes molded case), 3-phase, ≤ 600 V, ≤ 600 A, normally open (NO)	26 607.0	3	0.000 112 752	77 692 576	18.67	8.61	8.73
		E12-221	Circuit breaker, fixed (includes molded case), 3-phase, ≤ 600 V, > 600 A, normally closed (NC)	88 546.5	1	0.000 011 294	75 667 016		13.62	13.62
		E12-222	Circuit breaker, fixed (includes molded case), 3-phase, ≤ 600 V, > 600 A, normally open (NO)	583.2	2	0.003 429 339	2 554 428	37.50	2.69	3.03
	Fixed (molded case)	E12-311	Circuit breaker, fixed (molded case), 600 V, single phase, normally closed (NC)	7027.5	1	0.000 142 299	61 560 528	1.00		1.00
	Metal clad (drawout)			9529.8	179	0.018 783 250	466 373	9.58	2.12	4.33
		E12-411	Circuit breaker, metal clad (drawout), ≤ 600 V, ≤ 600 A, normally closed (NC)	5705.6	18	0.003 154 788	2 776 732	6.50	2.02	2.02
		E12-412	Circuit breaker, metal clad (drawout), ≤ 600 V, ≤ 600 A, normally open (NO)	911.2	4	0.004 389 750	1 995 558	6.00	2.93	2.94
		E12-421	Circuit breaker, metal clad (drawout), ≤ 600 V, > 600 A, normally closed (NC)	2290.1	153	0.066 809 897	131 118	9.90	2.56	26.74
		E12-422	Circuit breaker, metal clad (drawout), ≤ 600 V, > 600 A, normally open (NO)	622.9	4	0.006 421 989	1 364 063	2.00	2.38	2.37
	Oil filled			1573.9	640	0.406 641 344	21 542	19.01	28.83	30.54
		E12-512	Circuit breaker, oil filled, > 5 kV, normally closed (NC)	1392.3	631	0.453 204 694	19 329	18.98	28.84	30.56
		E12-511	Circuit breaker, oil filled, > 5 kV, Normally open (NO)	181.6	9	0.049 569 941	176 720	23.75	8.00	20.60
	SF6 filled	E12-610	Circuit breaker, SF6 filled, normally closed (NC)	315.2	418	1.326 315 057	6605	12.81	51.03	42.52
	Vacuum			3170.7	96	0.030 277 684	289 322	10.71	0.61	2.91
		E12-711	Circuit breaker, vacuum, < 15 kV, < 600 A, normally closed (NC)	514.4	3	0.005 832 348	1 501 968	5.33	0.05	0.06

		E12-712[a]	Circuit breaker, vacuum, < 15 kV, < 600 A, normally closed (NC)	458.2	0	0.001 512 626	7 870 965		1.84	1.84
		E12-721	Circuit breaker, vacuum, < 15 kV, > 600 A, normally closed (NC)	1476.2	65	0.044 031 239	198 950	11.58	2.60	14.89
		E12-722	Circuit breaker, vacuum, < 15 kV, > 600 A, normally closed (NC)	716.8	28	0.039 061 903	224 259	9.39	0.35	0.49
		E12-730[a]	Circuit breaker, vacuum, > 15 kV	5.0	0	0.138 553 516	85 929			
Compressor	Refrigerant			1344.2	19	0.014 134 513	619 760	8.69	0.93	1.02
		H11-010	Compressor, refrigerant, ≤ 1 ton (3.52 kW)	74.7	2	0.026 780 146	327 108	9.00	1.31	1.53
		H11-020	Compressor, refrigerant, > 1 ton (3.52 kW)	1052.0	5	0.004 752 765	1 843 138	3.50	0.91	0.93
		H11-100	Compressor, refrigerant, screw	217.5	12	0.055 165 812	158 794	10.83	0.94	1.15
Computer				406.3	100	0.246 142 641	35 589	4.30	4.82	23.48
	Control system server	C02-200	Computer, control system server	156.9	94	0.598 997 888	14 624	4.52	4.65	27.62
	Personal computer (PC) workstation	C02-100	Computer, PC workstation	249.3	6	0.024 063 554	364 036	1.90	5.09	4.09
Condenser				3972.6	305	0.076 775 438	114 099	8.10	2.83	4.91
	Double tube	H12-100	Condensers, double tube	298.7	8	0.026 781 865	327 087	2.50	2.63	2.63
	Propeller type fans/coils	H12-200	Condensers, propeller type fans with coils, direct expansion (DX)	2097.2	267	0.127 309 780	68 809	8.18	1.98	4.91
	Shell and tube	H12-300	Condenser, shell and tube	1576.7	30	0.019 027 462	460 387	9.50	6.86	7.06
Control center	Motor/load center	C03-100	Control center, motor/load center	1109.4	12	0.010 816 417	809 880	5.03	6.40	6.38
Control panel				6247.8	73	0.011 684 020	749 742	2.86	4.29	4.36
	Generator	C04-100	Control panel, generator, w/o switchgear	1808.4	30	0.016 589 350	528 050	4.38	0.62	1.45
	Heating, ventilation, and air conditioning (HVAC)/chillers/air-handling unit (AHU)	C04-200	Control panel, HVAC/chillers/AHU, w/o switchgear	3841.9	32	0.008 329 286	1 051 711	2.07	1.41	1.45
	Switchgear controls	C04-300	Control panel, switchgear controls	597.6	11	0.018 407 130	475 903	1.27	7.01	6.96

Control system				605.1	385	0.636 294 482	13 767	5.35	0.92	1.68
	≤ 1000 acquisition points	C12-100	Control system, ≤ 1000 acquisition points	384.7	99	0.257 318 645	34 043	1.73	1.26	1.43
	> 1000 acquisition points	C12-200	Control system, > 1000 acquisition points	220.3	286	1.298 060 184	6749	6.75	0.88	1.72
Convector	Fin tube baseboard			6387.9	8	0.001 252 62	6 994 782	2.44	0.13	0.15
		H13-110	Convector, fin tube baseboard, electric	1519.8	8	0.005 263 936	1 664 154	2.44	0.33	0.43
		H13-120[a]	Convector, fin tube baseboard, steam or hot water	4868.2	0	0.000 142 384	83617694		0.08	0.08
Cooling tower				2063.7	556	0.269 418 665	32514	13.56	1.50	2.24
	Atmospheric type (w/o fans)	H14-100	Cooling tower, atmospheric type (w/o fans, motors, and internal lift pump)	323.7	24	0.074 137 736	118158	88.92	0.99	1.14
	Atmospheric type (with fans)	H14-300	Cooling tower, atmospheric type (with fans, motors, and internal lift pump)	1037.4	502	0.483 905 897	18103	8.77	4.34	8.28
	Evaporative type (w/o fans)	H14-200	Cooling tower, evaporative type (w/o fans, motors, and internal lift pump)	515.3	3	0.005 821 372	1 504 800	16.67	1.44	1.46
	Evaporative type (with fans)	H14-400	Cooling tower, evaporative type (with fans, motors, and internal lift pump)	187.2	27	0.144 194 894	60 751	6.25	3.83	4.78
Damper assembly				18 711.9	74	0.003 954 699	2 215 086	23.10	0.07	0.65
	Motor operated	H15-100	Damper assembly, motor operated	15 793.2	48	0.003 039 287	2 882 255	28.73	0.07	0.54
	Pneumatically operated	H15-200	Damper assembly pneumatically operated	2918.7	26	0.008 907 946	983 392	11.83	4.00	59.87
Dehumidifier	> 10 lb/h (4.54 kg/h)	H16-100	Dehumidifier, > 4.54 kg/h (10 lb/h)	98.3	68	0.691 808 122	12 662	16.26	17.27	32.31
Direct fired furnace				1301.1	404	0.310 517 283	28 211	3.64	13.86	23.35
	≤ 500 MB/h	H17-100	Direct fired furnace, ≤ 500 MBH (147 kW)	161.4	6	0.037 173 459	235 652	0.83	3.33	3.82
	> 500 MB/h	H17-200	Direct fired furnace, >500 MBH (147 kW)	1139.6	398	0.349 230 237	25 084	3.67	15.69	24.90
Distribution panel				7939.1	31	0.003 904 724	2 243 436	20.86	3.4	11.70

	≤ 225 A	E13-100	Distribution panel, ≤ 225 A, circuit breakers, not included (wall mount unit)	6552.6	25	0.003 815 271	2 296 036	22.69	1.41	10.90
	> 225 A	E13-200	Distribution panel, > 225 A, circuit breakers, not included (wall mount unit)	1386.5	6	0.004 327 482	2 024 272	16.00	10.06	14.34
Drive				4534.9	169	0.037 266 634	235 063	13.08	2.15	14.04
	Adjustable speed	E14-100	Drive, adjustable speed	3158.4	96	0.030 395 480	288 201	15.51	3.45	22.10
	Variable frequency	E14-200	Drive, variable frequency	1376.5	73	0.053 032 158	165 183	9.07	1.28	7.59
Engine				1245.6	2007	1.611 246 868	5437	1.36	2.87	2.71
	Diesel	E15-100	Engine, diesel	207.2	134	0.646 760 906	13 544	9.64	3.27	4.11
	Gas	E15-200	Engine, gas	1038.4	1873	1.803 679 412	4857	1.00	0.75	0.94
Evaporator	Coil			8150.2	40	0.004 907 850	1 784 896	13.03	0.27	0.29
		H18-100	Evaporator, direct expansion, coil	7114.1	31	0.004 357 533	2 010 312	14.55	0.27	0.29
		H18-120	Evaporator, direct expansion, shell tube	1036.1	9	0.008 686 501	1 008 461	5.17	0.28	0.30
Fan				19 708.4	1549	0.078 595 830	111 456	10.70	2.09	3.71
	Centrifugal	H19-100	Fan, centrifugal	11 895.7	577	0.048 504 894	180 600	10.51	1.71	3.57
	Propeller/disc	H19-200	Fan, propeller/disc	3857.7	649	0.168 236 811	52 069	10.88	2.09	4.37
	Tubeaxial	H19-300	Fan, tubeaxial	2244.8	69	0.030 737 667	284 992	5.51	4.04	4.09
	Vaneaxial	H19-400	Fan, vaneaxial	1710.3	254	0.148 515 645	58 984	14.24	1.10	1.61
Filter				5796.7	33	0.005 692 936	1 538 749	11.66	0.30	0.36
	Electrical	E16-200[a]	Filter, electrical, tempest	342.1	0	0.002 026 405	5 875 341			
	Mechanical			5454.6	33	0.006 049 940	1 447 948	11.66	0.30	0.36
		H20-100	Filter, mechanical, air regulator set	3314.5	22	0.006 637 450	1 319 784	15.33	0.05	0.08
		H20-200[a]	Filter, mechanical, fuel oil	743.2	0	0.000 932 659	12 765 459		0.49	0.49
		H20-300	Filter, mechanical, lube oil	1396.9	11	0.007 874 695	1 112 424	3.95	1.47	1.72
Fuse				10 226.0	483	0.047 232 405	185 466	4.00		4.00
	> 15 kV	E17-300	Fuse, > 15 kV	4756.7	483	0.101 541 423	86 270	4.00		4.00
	> 5 kV ≤ 15 kV	E17-200[a]	Fuse, > 5 kV ≤ 15 kV	3590.5	0	0.000 193 050	61 672 329			
	0 kV to 5 kV	E17-100[a]	Fuse, 0 kV to 5 kV	1878.8	0	0.000 368 923	32 271 812			
Gauge	Fluid level	C05-100	Gauge, fluid level	830.2	4	0.004 817 989	1 818 186	3.31	7.13	6.04
Generator				4538.6	2283	0.503 018 519	17 415	23.24	2.93	3.93

	Diesel engine			3045.1	1305	0.428 550 581	20 441	19.29	2.02	3.08
		E18-111	Generator, diesel engine, packaged, < 250 kW, continuous	15.0	16	1.063 558 550	8 237			
		E18-112	Generator, diesel engine, packaged, < 250 kW, standby	857.8	281	0.327 590 557	26 741	12.24	1.69	4.88
		E18-121	Generator, diesel engine, packaged, 250 kW to 1.5 MW, continuous	266.0	155	0.582 686 262	15 034	25.74	0.52	1.15
		E18-122	Generator, diesel engine, packaged, 250 kW to 1.5 MW, standby	1439.8	358	0.248 652 553	35 230	12.95	1.72	2.63
		E18-211	Generator, diesel engine, unpackaged, 750 kW to 7 MW, continuous	180.6	328	1.815 727 611	4825	25.08	3.86	5.00
		E18-212	Generator, diesel engine, unpackaged, 750 kW to 7 MW, standby	285.9	167	0.584 093 735	14 998	23.91	2.57	3.11
	Gas turbine			983.7	485	0.493 016 528	17 768	25.05	2.39	2.72
		E19-111	Generator, gas turbine, packaged, 750 kW to 7 MW, continuous	185.5	295	1.590 684 138	5507	27.31	0.83	1.23
		E19-112	Generator, gas turbine, packaged, 750 kW to 7 MW, standby	612.4	113	0.184 526 491	47 473	6.05	4.40	4.42
		E19-211	Generator, gas turbine, unpackaged, 750 kW to 7 MW, continuous	185.9	77	0.414 185 923	21 150	50.33	13.26	15.87
	Hydro turbine	E20-000	Generator, hydro turbine	90.4	27	0.298 790 286	29 318	78.36	238.44	310.21
	Natural gas			281.4	250	0.888 285 342	9862	5.87	139.75	64.13
		E21-110	Generator, natural gas, < 250 kW, continuous	7.4	5	0.674 926 036	12 979	1.50		1.50
		E21-120	Generator, natural gas, < 250 kW, standby	222.4	31	0.139 419 404	62 832	6.33	32.87	34.60
		e21-210	generator, natural gas, ≥ 250 kW, continuous	51.7	214	4.140 691 264	2116		191.73	71.13
	Steam	E23-000	Generator, steam, heat recovery	20.5	86	4.185 891 452	2093	162.40		45.84
	Steam turbine	E22-000	Generator, steam turbine	117.4	130	1.107 687 280	7908	100.59	288.24	263.61
Heat exchanger				4858.5	272	0.055 984 436	156 472	10.81	1.11	1.74

	Boiler system	H21-100	Heat exchanger, boiler system, steam	964.0	164	0.170 129 316	51 490	7.22	18.15	19.15
	Lube oil	H21-200	Heat exchanger, lube oil	546.2	15	0.027 462 330	318 982	12.21	6.52	14.46
	Radiator	H21-310	Heat exchanger, radiator, small tube	1801.7	65	0.036 076 572	242 817	12.55	0.23	0.60
	Water to water	H21-400	Heat exchanger, water to water	1546.6	28	0.018 104 293	483 863	10.10	0.38	0.86
Heat pump	All types	H22-000	Heat pump	1330.4	82	0.061 635 471	142 126	3.26	0.76	6.37
Heater	Lube/fuel oil or jacket water	E24-110	Heater, lube/fuel oil or jacket water, electric	768.1	62	0.080 713 618	108 532	3.13	1.21	1.28
Humidifier	All types	H23-000	Humidifier	1569.1	38	0.024 217 472	361 722	4.11	1.86	2.00
Humistat assembly	All types	H24-000	Humistat assembly	643.3	10	0.015 544 284	563 551	1.00		1.00
Inverter	All types	E25-000	Inverter, all types	612.1	38	0.062 079 275	141 110	17.45	3.93	7.59
Line conditioner	All types	E26-000[a]	Line conditioner, all types	10.7	0	0.064 971 423	183 247			
Meter				18 288.1	26	0.001 421 689	6 161 684	38.78	0.38	1.80
	Electric	C06-100	Meter, electric	15 067.2	7	0.000 464 587	18 855 470	1.29	3.29	3.10
	Fuel	C06-200	Meter, fuel	238.2	13	0.054 567 200	160 536	72.00		72.00
	Water	C06-300	Meter, water	2982.7	6	0.002 011 594	4 354 756	4.75	0.01	0.04
Motor	Electric			33 939.9	567	0.016 705 988	524 363	29.11	1.09	3.59
		E29-100	Motor, electric, dc	1513.9	119	0.078 605 141	111 443	67.60	0.42	0.97
		E29-210	Motor, electric, induction, ≤ 600 V	3195.9	340	0.106 385 715	82 342	21.50	14.55	53.01
		E29-220	Motor, electric, induction, > 600 V	429.9	11	0.025 584 819	342 391	4.44	3.29	3.31
		E29-310[a]	Motor, electric, single phase, ≤ 5 A	25 377.5	0	0.000 027 314	435 895 106		0.49	0.49
		E29-320	Motor, electric, single phase, >5 A	1455.1	1	0.000 687 237	12 746 688	3.00	0.71	0.72
		E29-410	Motor, electric, synchronous, ≤ 600 V	1726.6	94	0.054 441 911	160 905	7.34	1.77	6.37
		E29-420	Motor, electric, synchronous, > 600 V	241.0	2	0.008 298 661	1 055 592	36.00	3.00	4.65
Motor generator set	3 phase			509.9	23	0.045 104 339	194 216	6.71	0.84	0.84
		E27-120	Motor generator set, 3 phase, 400 Hz	202.6	1	0.004 937 036	1 774 344	8.00	2.87	2.89

		E27-110	Motor generator set, 3 phase, 60 Hz	307.4	22	0.071 573 093	122 392	6.62	0.82	0.83
Motor starter				4056.8	33	0.008 134 545	1 076 889	4.33	0.62	1.34
	≤ 600 V	E28-100	Motor starter, ≤ 600 V	3505.6	28	0.007 987 258	1 096 747	3.37	0.72	1.66
	> 600 V	E28-200	Motor starter, > 600 V	551.2	5	0.009 071 298	965 683	9.15	0.48	0.87
Network hub				234.0	2	0.008 545 408	1 025 112	2.75		2.75
	Ethernet	C07-100	Network hub, Ethernet	229.0	2	0.008 732 057	1 003 200	2.75		2.75
	Fiber-optic	C07-200[a]	Network hub, fiber-optic	5.0	0	0.138 553 516	85 929			
Network printer				13 311.4	4682	0.351 727 580	24 906	1.69	1.55	3.29
	Inkjet	NWP-100	Network printer, inkjet	1260.0	670	0.531 744 876	16 474	1.74	1.78	5.57
	Laser	NWP-200	Network printer, laser	12 051.4	4012	0.332 906 396	26 314	1.68	1.50	2.87
Oil cooler	All types	E30-000	Oil cooler	92.9	3	0.032 302 791	271 184	13.25	0.50	2.20
Pipe				14 886.9	22	0.001 477 814	5 927 674	8.38	7.72	7.72
	Flex			1818.8	10	0.005 498 167	1 593 258	3.38	4.00	3.50
		H25-112	Pipe, flex, non-reinforced, > 100 mm (4 in)	206.3	3	0.014 544 485	602 290	3.33	4.00	3.60
		H25-111	Pipe, flex, reinforced, < 100 mm (4 in)	273.8	3	0.010 957 670	799 440	8.00		8.00
		H25-122	Pipe, flex, reinforced, > 100 mm (4 in)	1338.7	4	0.002 987 876	2 931 848	2.25		2.25
	Refrigerant			11 221.0	6	0.000 534 713	16 382 612	9.33	3.06	3.20
		H25-310	Pipe, refrigerant, < 25 mm per 30.5 m (1 in per 100 ft)	7913.6	3	0.000 379 094	23 107 704	10.67	2.00	2.11
		H25-320	Pipe, refrigerant, 25 mm to 80 mm per 30.5 m (1 in to 3 in per 100 ft)	3307.4	3	0.000 907 065	9 657 520	8.00	8.78	8.73
	Water			1847.1	6	0.003 248 338	2 696 764	14.08	8.00	8.01
		H25-410[a]	Pipe, water, ≤ 50 mm per 30.5 m (2 in per 100 ft)	462.5	0	0.001 498 852	7 943 294			
		H25-450[a]	Pipe, water, > 300 mm per 30.5 m (12 in per 100 ft)	8.2	0	0.084 984 454	140 094			
		H25-420	Pipe, water, 50 mm to 100 mm per 30.5 m (2 in to ≤ 4 in per 100 ft)	292.3	6	0.020 530 031	426 692	14.08		14.08
		H25-430[a]	Pipe, water, 100 mm to 200 mm per 30.5 m (4 in to 8 in per 100 ft)	268.7	0	0.002 579 961	4 614 729			

		H25-440[a]	Pipe, water, 200 mm to 300 mm per 30.5 m (8 in to 12 in per 100 ft)	815.6	0	0.000 849 893	14 008 612		8.00	8.00
Pressure control assembly	All types	C08-000	Pressure control assembly	896.3	82	0.091 485 687	95 753	8.10	3.53	4.08
Pressure regulator	Hot gas	C09-100	Pressure regulator, hot gas	2711.4	29	0.010695434	819 041	2.94	1.68	19.52
Programmable logic controller	All types	C10-000	Programmable logic controller (PLC)	203.9	6	0.029 422 829	297 728	23.50	2.00	73.27
Pump				25 386.6	3097	0.121 993 479	71 807	11.83	1.75	6.24
	Centrifugal			23 888.4	2917	0.122 109 700	71 739	11.91	1.92	6.47
		H26-110	Pump, centrifugal, with drive	21 835.4	2655	0.121 591 798	72 045	11.95	2.21	7.95
		H26-120	Pump, centrifugal, w/o drive	2052.9	262	0.127 621 356	68 641	11.28	1.04	1.52
	Positive displacement	H26-200	Pump, positive displacement	1498.2	180	0.120 140 438	72 915	7.91	0.70	4.74
Recloser (interrupter)				8368.5	85	0.010 157 168	862 445	5.00	6.02	5.97
	Electronic	E31-100	Recloser (interrupter), electronic	1949.4	13	0.006 668 840	1 313 572			
	Hydraulic	E31-200	Recloser (interrupter), hydraulic	2939.1	58	0.019 734 144	443 901		8.00	8.00
	Undefined type	E31-099[a]	Recloser (interrupter), undefined type	3480.0	14	0.004 022 941	2 177 511	5.00	5.00	5.00
Rectifiers	All types	E32-000	Rectifiers, all types	563.4	2	0.003 549 686	2 467 824	16.00	3.45	3.47
Relay	Electromechanical			5307.4	5	0.000 942 089	9 298 488	26.33	3.63	3.70
		E33-110	Relay, electromechanical, differential, differential voltage	828.1	2	0.002 415 059	3 627 240	35.50	4.28	4.51
		E33-120[a]	Relay, electromechanical, drawout	790.4	0	0.000 876 976	13 576 000			
		E33-130	Relay, electromechanical, overcurrent	3688.8	3	0.000 813 265	10 771 400	8.00	3.35	3.36
Router	Wired	RTR-100	Router, wired	2763.5	262	0.094 806 605	92 399	2.14	1.13	3.37
Sending unit				43 914.1	171	0.003 893 968	2 249 633	6.39	0.07	1.56
	Air velocity	C13-100	Sending unit, air velocity	7492.2	47	0.006 273 186	1 396 420	6.96	0.04	1.30
	Pressure	C13-200	Sending unit, pressure	7565.9	95	0.012 556 363	697 654	5.82	0.10	2.22
	Temperature	C13-300	Sending unit, temperature	28 856.0	29	0.001 004 991	8 716 496		0.25	0.39
Server				8145.9	540	0.066 290 672	132 145	3.02	1.00	2.41

	Blade	SVR-100	Server, blade	526.0	25	0.047 528 517	18 310	2.68	0.70	2.29
	Rack mount	SVR-200	Server, rack mount	6323.2	387	0.061 203 480	143 129	3.02	0.98	2.38
	Tower case	SVR-300	Server, tower case	1296.8	128	0.0987 065 589	88 748	3.08	1.09	2.49
Strainer				9788.4	88	0.008 990 193	974 395	16.96	0.35	0.62
	Air or gaseous	H27-110	Strainer, air or gaseous, air systems	304.2	1	0.003 287 222	266 4864			
	Liquid			9484.2	87	0.009 173 117	954 964	16.96	0.35	0.62
		H27-210[a]	Strainer, liquid, coolant	488.2	0	0.001 419 921	8 384 847		1.62	1.62
		H27-220[a]	Strainer, duplex fuel/lube oil	280.2	0	0.002 473 565	4 813 224		0.86	0.86
		H27-230[a]	Strainer, liquid, fuel oil	460.4	0	0.001 505 416	7 908 659		1.67	1.67
		H27-240	Strainer, liquid, lube oil	1161.2	25	0.021 528 741	406 898	14.29	1.85	4.12
		H27-251	Strainer, water, ≤ 100 mm (4 in)	6466.1	25	0.003 866 327	2 265 716	2.25	0.00	0.00
		H27-252	Strainer, water, > 100 mm (4 in)	628.1	37	0.058 908 203	148 706	25.58	4.03	8.99
Switch				36 667.8	385	0.010 499 665	834 312	8.63	2.01	7.08
	Automatic transfer			2883.7	101	0.035 024 398	250 111	7.89	2.40	2.96
		E34-110	Switch, automatic transfer, ≤ 600 V, > 600 A	1030.8	27	0.026 193 875	334 429	2.66	8.98	8.32
		E34-120	Switch, automatic transfer, ≤ 600 V, 0 A to 600 A	1852.9	74	0.039 936 775	219 347	9.90	1.82	2.42
	Disconnect			19 349.5	23	0.001 188 660	7 369 646	17.83	1.75	1.90
		E34-211	Switch, disconnect, enclosed, ≤ 600 V	8372.7	6	0.000 716 616	12 224 124		2.09	2.09
		E34-212	Switch, disconnect, enclosed, > 600 V to ≤ 5 kV	2238.8	2	0.000 893 351	9 805 776	46.00	3.03	3.38
		E34-213	Switch, disconnect, enclosed, > 5 kV	2091.2	15	0.007 172 820	1 221 277	15.82	2.08	2.86
		E34-222[a]	Switch, disconnect, fused, dc, > 600 A; ≤ 600 V	861.5	0	0.000 804 591	14 797 365			
		E34-221[a]	Switch, disconnect, fused, dc, ≤ 600 A; ≤ 600 V	5785.4	0	0.000 119 811	99 372 047		0.54	0.54
	Electric	E34-310	Switch, electric, on/off breaker type, non-knife, ≤ 600 V	3115.2	2	0.000 642 008	13 644 684	1.00	0.01	0.01
	Float	E34-400	Switch, float, electric	2513.6	87	0.034 611 071	253 098	9.84	0.91	22.86
	Manual transfer			640.4	0	0.001 082 408	10 999 388			

		E34-510[a]	Switch, manual transfer, ≤ 600 V, ≤ 600 A	266.6	0	0.002 599 818	4 579 482			
		E34-520[a]	Switch, manual transfer, ≤ 600 V, > 600 A	373.8	0	0.001 854 517	6 419 906			
	Oil filled	E34-610[a]	Switch, oil filled, ≥ 5 kV	300.2	0	0.002 308 614	5 157 129		1.38	1.38
	Pressure	E34-700	Switch, pressure	6661.0	169	0.025 371 639	345 267	7.04	3.08	16.89
	Static			921.5	2	0.002 170 468	4 035 996	13.00	2.04	2.11
		E34-810[a]	Switch, static, ≤ 600 V, 0 A to 600 A	498.4	0	0.001 390 875	8 559 953		0.03	0.03
		E34-820	Switch, static, ≤ 600 V, > 600 A ≤ 1000 A	130.0	1	0.007 692 794	1 138 728	2.00	0.05	0.08
		E34-830	Switch, static, ≤ 600 V, > 1000 A	271.7	1	0.003 680 066	2 380 392	24.00	3.47	3.58
		E34-850[a]	Switch, static, with insulated-gate bipolar transistor (IGBT) technology	15.3	0	0.045 210 636	26 3341			
		E34-860[a]	Switch, static, w/o IGBT technology	6.0	0	0.114 582 754	103 906			
	Vibration	E34-900	Switch, vibration	282.7	1	0.003 537 644	2 476 224		0.50	0.50
Switchgear				6747.6	47	0.006 965 393	1 257 646	24.32	3.35	3.56
	Bare bus			4229.7	42	0.009 929 718	882 200	24.31	3.64	3.94
		E36-110	Switchgear, bare bus, ≤ 600 V (circuit breaker not included)	2493.6	23	0.009 223 683	949 729	7.91	4.28	4.35
		E36-130	Switchgear, bare bus, > 5 kV (circuit breaker not included)	895.7	15	0.016 746 168	523 105	2.27	1.28	1.30
		E36-120	Switchgear, bare bus, > 600 V to ≤ 5 kV (circuit breaker not included)	840.4	4	0.004 759 530	1 840 518	195.75	6.59	9.67
	Insulated bus			1713.6	5	0.002 917 820	3 002 242	24.40	2.90	2.97
		E36-210[a]	Switchgear, insulated bus, ≤ 600 V (circuit breaker not included)	505.2	0	0.001 372 077	8 677 224		3.18	3.18
		E36-220	Switchgear, insulated bus, > 600 V to ≤ 5 kV (circuit breaker not included)	405.8	2	0.004 928 902	1 777 272	5.00	0.77	0.78
		E36-230	Switchgear, insulated bus, > 5 kV (circuit breaker not included)	802.7	3	0.003 737 584	2 343 760	37.33	14.01	14.43

	Load center (free standing unit)	E36-300[a]	Switchgear, load center (free standing unit)	804.3	0	0.000 861 792	13 815 200		0.59	0.59
Tank				4876.1	137	0.028 096 327	311 785	18.02	1.11	3.10
	Air	E37-110	Tank, air, receiver	1519.1	22	0.014 482 011	604 888	11.53	1.25	1.63
	Liquid			3357.0	115	0.034 257 224	255 712	18.99	0.88	5.31
		E37-210	Tank, liquid, day, fuel	484.8	2	0.004 125 040	2 123 616	5.00	0.31	0.35
		E37-220	Tank, liquid, fuel	614.7	21	0.034 162 930	256 418	13.80	1.28	2.52
		E37-230	Tank, liquid, water	2257.4	92	0.040 754 653	214 945	20.57	0.91	7.23
Thermocouple	All types	C14-000	Thermocouple	5761.5	101	0.017 530 270	499 707	13.48	14.00	479.86
Thermostat	Radiator	C15-100	Thermostat, radiator	8735.0	153	0.017 515 835	500 119	3.16	1.13	2.00
Transducer				26 305.4	81	0.003 079 211	2 844 885	3.74	0.06	0.09
	Flow	C16-100	Transducer, flow	1188.0	5	0.004 208 706	2 081 400	2.00	1.17	1.18
	Pressure	C16-200	Transducer, pressure	2139.0	28	0.013 090 212	669 202	7.50	2.28	3.07
	Temperature	C16-300	Transducer, temperature	22 978.4	48	0.002 088 916	4 193 563	1.89	0.02	0.03
Transformer				164 239.4	456	0.002 776 435	3 155 125	14.92	10.83	11.43
	Dry			96 735.4	248	0.002 563 695	3 416 944	3.63	2.77	3.40
		E38-111	Transformer, dry, air cooled, ≤ 500 kVA	86095.4	226	0.002 624 996	3 337 148	2.13	2.36	2.33
		E38-112	Transformer, dry, air cooled, > 500 kVA ≤ 1500 kVA	1700.3	3	0.001 764 436	4 964 760	2.00	5.41	36.50
		E38-113[a]	Transformer, dry, air cooled, > 1500 kVA ≤ 3000 kVA	999.7	0	0.000 693 337	17 171 772		4.39	4.39
		E38-114[a]	Transformer, dry, air cooled, > 3000 kVA ≤ 5000 kVA	1142.2	0	0.000 606 854	19 618 918		5.50	5.50
		E38-121	Transformer, dry, isolation, delta wye, < 600 V	6797.8	19	0.002 795 011	3 134 156	21.26	0.93	2.52
	Liquid			67 504.0	208	0.00 3081 299	2 842 957	36.89	13.29	14.16
		E38-211	Transformer, liquid, forced air, ≤ 5000 kVA	5849.5	52	0.008 889 630	985 418	8.69	0.98	2.08
		E38-212	Transformer, liquid, forced air, > 5000 kVA ≤ 10 000	600.6	23	0.038 292 418	228 766	251.00	22.96	23.60
		E38-213	Transformer, liquid, forced air, >10 000 kVA ≤ 50 000 kVA	482.1	34	0.070 518 976	124 222	965.33	21.69	24.34
		E38-214	Transformer, liquid, forced air, > 50 000	18.6	24	1.289 752 650	6792	11.95	2.43	5.30
		E38-221	Transformer, liquid, non-forced air, ≤ 3000 kVA	59 708.0	63	0.001 055 134	8 302 262	2.33	2.00	2.02

		E38-222	Transformer, liquid, non-forced air, > 3000 kVA ≤ 10 000 kVA	190.7	1	0.005 242 671	1 670 904	1.00	2.67	2.50
		E38-223	Transformer, liquid, non-forced air, > 10 000 kVA ≤ 50 000 kVA	654.3	11	0.016 811 614	521 068	6.09	0.58	0.65
UPS				1232.8	65	0.052 726 440	166 141	5.24	2.08	6.48
	Rotary	E39-100	Uninterruptible power supply (UPS), rotary	134.7	2	0.014 848 263	589 968	8.75	6.11	7.81
	Small computer room floor	E39-200	Uninterruptible power supply (UPS), small computer room floor	724.7	41	0.056 575 669	154 837	6.25	2.12	3.74
	Solid state			373.4	22	0.058 919 780	148 677	2.93	1.14	11.44
		E39-310	Uninterruptible power supply (UPS), solid state, 60 Hz/module	357.3	22	0.061 578 810	142 257	2.93	1.09	13.83
		E39-320[a]	Uninterruptible power supply (UPS), solid state, with IGBT technology	16.1	0	0.042 990 437	276 941		1.30	1.30
Valve				157 135.7	1345	0.008 559 481	1 023 427	11.94	2.62	8.08
	3-way			16 490.6	7	0.000 424 484	20 636 822	5.86	0.52	0.81
		H28-110	Valve, 3-way, diverting/sequencing	736.9	4	0.005 428 034	1 613 844	9.13	0.02	0.59
		H28-120	Valve, 3-way, mixing control	15 753.7	3	0.000 190 432	46 000 792	1.50	1.02	1.03
	Backflow preventer	H28-200	Valve, backflow preventer	742.6	30	0.040 401 283	216 825	13.27	1.11	15.63
	Ball			2703.6	5	0.001 849 362	4 736 770	1.20	0.19	0.24
		H28-310[a]	Valve, ball, normally closed (NC)	1092.7	0	0.000 634 368	18 768 000		0.19	0.19
		H28-320	Valve, ball, normally open (NO)	1611.0	5	0.003 103 705	2 822 434	1.20		1.20
	Butterfly			18 225.8	26	0.001 426 553	6 140 677	3.88	0.55	0.67
		H28-410	Valve, butterfly, normally closed (NC)	2809.7	26	0.009 253 770	946 641	3.88	1.01	1.67
		H28-420[a]	Valve, butterfly, normally open (NO)	15 416.1	0	0.000 044 963	64 793 976		0.48	0.48
	Check	H28-500	Valve, check	4699.2	44	0.009 363 323	935 565	26.69	1.11	8.60
	Control			22 796.4	647	0.028 381 678	308 650	17.32	0.50	15.34
		H28-610	Valve, control, normally closed (NC)	17 563.1	388	0.022 091 808	396 527	17.76	0.23	8.54

		H28-620	Valve, control, normally open (NO)	5233.3	259	0.049 490 515	177 004	16.93	1.56	38.85
	Expansion	H28-700[a]	Valve, expansion	1984.1	0	0.000 349 348	34 080 094			
	Gate			19 302.5	97	0.005 025 268	1 743 191	10.45	0.81	33.26
		H28-830	Valve, gate, double flap	173.2	76	0.438 785 195	19 964	10.67		10.67
		H28-810	Valve, gate, normally closed (NC)	1830.5	8	0.004 370 485	2 004 354	7.50	0.59	0.99
		H28-820	Valve, gate, normally open (NO)	17 298.8	13	0.000 751 498	11 656 721	9.31	1.30	150.13
	Globe			41 402.3	66	0.001 594 112	5 495 221	16.65	1.00	1.74
		H28-910[a]	Valve, globe, normally closed (NC)	22 125.4	0	0.000 031 328	80 035 718		1.00	1.00
		H28-920	Valve, globe, normally open (NO)	19 277.0	66	0.003 423 773	2 558 581	16.65	0.40	129.72
	Plug			15 233.3	148	0.009 715 539	901 648	1.81	0.05	1.59
		H28-A10	Valve, plug, normally closed (NC)	8845.9	123	0.013 904 727	630 002	1.37	0.05	1.17
		H28-A20	Valve, plug, normally open (NO)	6387.4	25	0.003 913 946	2 238 151	4.00		4.00
	Reducing	H28-B10	Valve, reducing, makeup water	701.9	100	0.142 473 496	61 485	5.56	0.59	17.99
	Relief	H28-C00	Valve, relief	10 598.4	165	0.015 568 452	562 676	7.55	102.91	137.61
	Suction	H28-D00	Valve, suction	2255.1	10	0.004 434 439	1 975 447	7.25	0.61	0.77
Valve operator				10 025.1	80	0.007 980 004	1 097 744	10.02	1.06	1.47
	Electric	C17-100	Valve operator, electric	3684.0	43	0.011 672 052	750 511	16.42	0.98	1.40
	Hydraulic	C17-200	Valve operator, hydraulic	68.2	6	0.087 937 681	99 616	3.00	2.16	2.20
	Pneumatic	C17-300	Valve operator, pneumatic	6272.8	31	0.004 941 961	1 772 576	2.92	0.98	1.76
Voltage regulator	Static	E40-100	Voltage regulator, static	3381.5	77	0.022 771 080	384 698	15.73	0.53	2.23
Water cooling coil	Fan coil unit	H29-100	Water cooling coil, fan coil unit	16 076.0	96	0.005 971 646	1 466 932	3.72	2.04	2.09
Water heater	Domestic hot water			1399.8	44	0.031 431 955	278 697	6.37	1.28	12.85
		H30-110	Water heater, domestic hot water, electric	957.5	19	0.019 843 370	441 457	9.64	0.82	29.64
		H30-130	Water heater, domestic hot water, gas	442.4	25	0.056 516 246	155 000	3.53	1.35	9.11
Workstation	All types	WST-000	Workstation	169 635.1	7948	0.046 853 516	186 966	0.73	0.62	1.11

[a] Failure rate calculated using 50% single-sided confidence interval.Part 2: Equipment reliability surveys conducted between 1976 and 1994.

5.3 Introduction

Clause 6 presents data derived from a series of electrical equipment surveys for specific types of equipment according to Table 3.

Table 3—Part 2 equipment reliability table reference guide

Electrical equipment types		Reference tables in Part 2: survey data from 1976 to 1989
Motors	> 50 hp (37.3 kW)	Table 23, Table 25
	> 200 hp (149 kW)	Table 16, Table 17, Table 18, Table 19, Table 20, Table 21, Table 22
	> 250 hp (187 kW)	Table 26
Generators		Table 5
Transformers	Power	Table 6, Table 8, Table 9, Table 10, Table 11, Table 12, Table 13, Table 14
	Rectifier	Table 7, Table 9, Table 10, Table 11, Table 12, Table 13, Table 15
Switchgear	Bus insulated	Table 4
	Bus bare	Table 4

5.4 1979 switchgear bus reliability data

The reliability of switchgear bus in industrial and commercial applications was investigated in a 1979 survey (see O'Donnell [B29] and *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 100) and the summarized failure rate and median outage duration time for the various subcategories of equipment are shown in Table 4. In this survey, the term *units* for a bus is defined as the total number of connected circuit breakers and connected switches. In the previous survey of 1974, the term *units* included the total number of connected circuit breakers or instrument transformer compartments. The total number of plants in the 1979 survey response was considerably greater than the 1974 survey; however the unit-year sample size was slightly less.

Table 4—Switchgear bus, indoor and outdoor 1979 survey data

Industry	Equipment subclass	Failure rate (failures per unit-year)	Median hours down time per failure
All	All	0.001 050	28
All	Insulated, above 600 V	0.001 129	28
All	Bare, all voltages	0.000 977	28
All	Bare, 0 V to 600 V	0.000 802	27
All	Bare, above 600 V	0.001 917	36
Petroleum/chemical	Insulated, above 600 V	0.002 020	40
Petroleum/chemical	Bare, all voltages	0.002 570	28
Petroleum/chemical	Bare, 0 V to 600 V	0.002 761	22
Petroleum/chemical	Bare, above 600 V	[a]	48

[a] Small sample size; fewer than eight failures.

The 1974 survey generated some controversy concerning bare and insulated buses; insulated bus equipment showed a significantly higher failure rate than bare bus above 600 V. An analysis of the 1974 database revealed that the majority of the data collected came from the petroleum/chemical industry. In the 1979 survey, the petroleum/chemical industry data was separated from the remaining industrial database. The resulting bare bus failure rate was significantly higher and the insulated bus failure rate lower in the 1979 survey than in the 1974 survey.

A comparison of the median downtime per failure in both surveys revealed no significant differences. It is important to emphasize that the duration of an outage is dependent on many factors, and without supplementary information on the operating procedures, maintenance type, spare parts inventory, etc., the data in these surveys should be viewed as general information.

Some important additional observations based on the 1979 survey are as follows:

a) Newer bus appears to experience a higher failure rate than older bus. This may be partly explained by improper installation, type of construction of new switchgear, etc., but is not completely consistent with the observation that failure rates are highly dependent on maintenance.

b) Outdoor bus shows a higher failure rate than indoor bus.

c) Primary and contributing causes of failures were investigated. Inadequate maintenance was one of the leading "suspected primary causes of failure" and exposure to contaminants (including dust, moisture, and chemicals) was the leading "contributing cause to failnre." This tends to support the data showing outdoor bus with a relatively high failure rate.

d) The survey results on type of failures show a surprisingly high percentage of line-to-line failures, rather than line-to-ground.

5.5 1980 generator survey data

5.5.1 Introduction

The results of the 1980 generator survey data (see IEEE Committee Report [B12]) are summarized in Table 5. A *unit* in this survey was defined to include the generator's driver and its ancillary equipment, including the device from which the generator's output is made available to the "outside" world. The term *unit-year* was defined as the summation of the running times reported for each generator.

Table 5—Generator survey data, 1980

Equipment subclass	Average downtime per failure (h)	Failure rate
Continuous service steam turbine driven	32.7	0.16 900 failures per unit-year
Emergency and standby units reciprocating engines driven	478.0	0.00 536 failures per hour in use
Reciprocating engines driven	[a]	0.01 350 failures per start attempt

[a] Small sample size; fewer than eight failures.

Two major categories (i.e., continuously applied units and emergency or standby applied units) emerged from an evaluation of the responses. All of the continuous units were steam turbine driven, and all of the emergency or standby units were reciprocating engine driven. An important point to note on the data for emergency and standby units: Failure to start for automatically started units was counted as a failure, whereas failure to start for manually started units was not counted as a failure.

5.5.2 Reliability/availability guarantees of gas turbine and combined cycle generating units

Many industrial firms are now purchasing gas turbine generating units or combined cycle units that include both a gas turbine and a steam turbine. In some cases, the specification contains a reliability/availability guarantee. *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 221 (see Ekstrom [B7]) contains one manufacturer's suggestion on how to write a reliability/availability guarantee when purchasing such units; this is a very thorough description of the factors that need to be considered along with the necessary definitions. *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 221 also contains some 1993 data on the reliability/availability of gas turbine units that was collected by an independent data collection organization.

5.6 1979 survey of the reliability of transformers

5.6.1 Introduction

A survey published in 1973-1974 raised some interesting questions and created some controversy (see IEEE Committee Report [B10]). The most controversial items in this survey concerned the average outage duration time after a transformer failure in relation to the failure restoration method, and the comparatively high failure rate for rectifier transformers.

The 1979 survey form (see IEEE Committee Report [B11]) was improved considerably, taking lessons learned from the 1973-1974 version. Items felt to be of little significance in the past were omitted and the form was simplified to maximize the response. Data relating specifically to transformer reliability, such as rating, voltage, age, and maintenance were included in the new form. The most significant categories in the failed unit data are the causes of failure, the restoration method, restoration urgency, the duration of failure, and the transformer age at time of failure. The survey form of the 1979 survey (published in 1983) is shown in the *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, on page 114.

5.6.2 Failure rate and restoration method for power and rectified transformers survey results

The survey response for power transformers is summarized in Table 6 and the survey response for rectifier transformers is summarized in Table 7.

Table 6—Power transformers (1979 survey)

Equipment subclass	Failure rate (failures per unit-year)	Average repair time (hours per failure)	Average replacement time (hours per failure)
All liquid filled	0.0062	356.1	85.1
Liquid filled 300 kVA to 10 000 kVA	0.0059	297.4	79.3
Liquid filled > 10 000 kVA	0.0153	1178.5[a]	192.0[a]
Dry 300 kVA to 10 000 kVA	[a]	[a]	[a]

[a] Small sample size; fewer than eight failures.

Table 7—Rectifier transformers (1979 survey)

Equipment subclass	Failure rate (failures per unit-year)	Average repair time (hours per failure)	Average replacement time (hours per failure)
All liquid filled	0.0190	2316.0	41.4
Liquid filled 300 kVA to 10 000 kVA	0.0153	1644.0[a]	38.7[a]
Liquid filled > 10 000 kVA	[a]	[a]	[a]

[a] Small sample size; fewer than eight failures.

The survey results for the liquid-filled power transformers compared favorably between the 1973-1974 and 1979 surveys: 0.0041 and 0.0062 failures per unit-year, respectively. The 1979 survey also confirmed the fact that the failure rate for rectifier transformers (i.e., 0.0190) is much higher than those for the other transformer categories (i.e., 0.0062). This may be due to the severe duties to which they were subjected and/or the harsh environments in which they are housed.

Table 6 and Table 7 include data on restoration time versus restoration method. The data clearly indicate that the restoration of a unit to service by repair rather than replacement results in a much longer outage duration in every case. This is consistent with previous survey results. Despite this fact, in most categories a larger number of units were restored to service by repair. These results show the obvious benefits in having spares at the site or readily available. The data also provides some of the information necessary in the preparation of an economic justification for spares. The averages shown represent only those cases where restoration work was begun immediately. Those instances in which the repair or replacement was deferred were excluded to avoid distorting the average restoration time data.

5.6.3 Failure rate versus age of power transformers

The survey response for power transformer failures as a function of their age is summarized in Table 8.

Table 8—Failure rate versus age of power transformers (1979 survey)

Equipment subclass	Age[a] (years)	Number of units	Sample size (unit-years)	Number of failures[b]	Failure rate (failures per unit-year)
Liquid filled 300 kVA to 10 000 kVA	1 to 10	638	2625.5	19	0.0072
Liquid filled 300 kVA to 10 000 kVA	11 to 25	715	8846.5	47	0.0053
Liquid filled 300 kVA to 10 000 kVA	> 25	397	5938.0	36	0.0060
Liquid filled > 10 000 kVA	1 to 10	27	144.0	0[c]	—
Liquid filled > 10 000 kVA	11 to 25	28	283.5	7[c]	0.0246[c]
Liquid filled > 10 000 kVA	> 25	9	158.0	2[c]	0.0126[c]

[a] Age was the age of the transformer at the end of the reporting period.
[b] Relay or tap changer faults were not considered in calculation of failure rates or repair and replacement times.
[c] Small sample size; fewer than eight failures.

An examination of Table 8 reveals that the failure rates for power transformers was approximately equal in all three age groups. It can be seen that slightly higher failure rates for transformer units aged 1 year to 10 years and for units greater than 25 years may be attributable to "infant mortality" and to units approaching the end of their life, respectively.

5.6.4 Failure-initiating cause

Table 9 summarizes the failure-initiating cause data for power and rectifier transformers. This table reveals that a large percentage of transformer failures were initiated by some type of insulation breakdown or transient over-voltages.

Table 9—Failure-initiating cause for power and rectifier transformers (1979 survey)

	All power transformers		All rectifier transformers	
Failure-initiating cause	**Number of failures[a]**	**Percentage**	**Number of failures**	**Percentage**
Transient overvoltage disturbance (switching surges, arcing ground fault, etc.)	18	16.4%	2	13.3%
Overheating	3	2.7%	1	6.7%
Winding insulation breakdown	32	29.1%	2	13.3%
Insulation bushing breakdown	15	13.6%	1	6.7%
Other insulation breakdown	6	5.5%	3	20.0%
Mechanical breaking, cracking, loosening, abrading, or deforming of static or structural parts	8	7.3%	3	20.0%
Mechanical burnout, friction, or seizing of moving parts	3	2.7%	2	13.3%
Mechanically caused damage from foreign source (digging, vehicular accident, etc.)	3	2.7%	0	0.0%
Shorting by tools or other metal objects	1	0.9%	0	0.0%
Shorting by birds, snakes, rodents, etc.	3	2.7%	0	0.0%
Malfunction of protective relay control device or auxiliary device	5	4.6%	0	0.0%
Improper operating procedure	4	3.6%	0	0.0%
Loose connection or termination	8	7.3%	1	6.7%
Other	1	0.9%	0	0.0%
Continuous overvoltage	0	0.0%	0	0.0%
Low voltage	0	0.0%	0	0.0%
Low frequency	0	0.0%	0	0.0%
Total	110	100.0%	15	100.0%

[a] The initiating cause was not specified for two failures.

5.6.5 Failure-contributing cause

Table 10 summarizes the failure-contributing cause for power and rectifier transformers. Normal deterioration from age and cooling medium deficiencies were reported to have contributed to a large number of both power and rectifier transformer failures.

Table 10 —Failure-contributing cause for power and rectifier transformers (1979 survey)

	All power transformers		All rectifier transformers	
Failure-contributing cause	Number of failures[a]	Percentage	Number of failures[b]	Percentage
Persistent overloading	1	1.1%	0	0%
Abnormal temperature	5	5.5%	1	7.1%
Exposure to aggressive chemicals, solvents, dusts, moisture, or other contaminants	13	14.4%	1	7.1%
Normal deterioration from age	12	13.3%	4	28.60%
Severe wind, rain, snow, sleet, or other weather conditions	4	4.4%	0	0.0%
Lack of protective device	2	2.2%	0	0.0%
Malfunction of protective device	7	7.8%	0	0.0%
Loss, deficiency, contamination, or degradation of oil or other cooling medium	9	10.0%	3	21.50%
Improper operating procedure or testing error	3	3.3%	0	0.0%
Inadequate maintenance	7	7.8%	3	21.50%
Others	27	30.0%	1	7.1%
Exposure to nonelectrical fire or burning	0	0.0%	0	0.0%
Obstruction of ventilation by foreign object or material	0	0.0%	0	0.0%
Improper setting of protective device	0	0.0%	0	0.0%
Inadequate protective device	0	0.0%	1	7.1%
Total	90	100.0%	140	100.0%

[a] Failure-contributing cause not specified for 22 failures.
[b] Failure-contributing cause not specified for two failures.

5.6.6 Suspected failure responsibility

Table 11 summarizes the suspected failure responsibility for power and rectifier transformer failures. The respondents believed that manufacturer defects and inadequate maintenance were responsible for the majority of power transformer failures (i.e., 59.3%). Table 11 shows that inadequate operating procedures were a more significant cause of rectifier transformer failures (i.e., 31.2%) than inadequate maintenance.

Table 11—Suspected failure responsibility for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures[a]	Percentage	Number of failures	Percentage
Manufacturer defective component or improper assembly	32	33.3	5	31.2
Transportation to site, improper handling	1	1.0	0	0.0
Application engineering, improper application	3	3.1	2	12.5
Inadequate installation and testing prior to start-up	6	6.3	0	0.0
Inadequate maintenance	25	26.0	2	12.5
Inadequate operating procedures	4	4.2	5	31.3
Outside agency—Personnel	3	3.1	0	0.0
Outside agency—Others	6	6.3	0	0.0
Others	16	16.7	2	12.5
Total	96	100.00	160	100.00

[a] Suspected failure responsibility not specified for 16 failures.

5.6.7 Maintenance cycle and extent of maintenance

The 1973-1974 survey asked the respondent to give an opinion of the maintenance quality as excellent, fair, poor, or none. It is very difficult to be completely objective in responding to this type of question. The 1979 survey, therefore, asked for a brief description of the extent of maintenance performed, the idea being to enable the reader to judge the benefits derived from a particular maintenance procedure. The large percentage of failures that resulted from inadequate maintenance shows the importance of a comprehensive preventive maintenance program and compilation of accurate data on the extent and frequency of the maintenance performed. Unfortunately, the response did not lend itself to reporting in tabular form. Maintenance information continues to be the most difficult to obtain and report for all equipment categories.

5.6.8 Type of failure

The 1979 survey limited the choices of failure type to "winding" and "other" as shown in Table 12 for power and rectifier transformers. Clearly, the most significant failure type was that occurring in power transformer windings.

Table 12—Type of failure for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures	Percentage	Number of failures	Percentage
Winding	59	53	8	50
Other	53	47	8	50

5.6.9 Failure characteristics

The failure characteristics of power and rectifier transformers are shown in Table 13. As would be expected, the survey results show that about 75% of transformer failures resulted in their removal from service by automatic protective devices; however, the percentage requiring manual removal was significant. Increasing use of transformer oil or gas analysis could be a factor here, enabling detection of incipient faults in their early stages, and thus permitting manual removal before a major failure occurs.

Table 13—Failure characteristic for power and rectifier transformers (1979 survey)

	All power transformers		All rectifier transformers	
Failure-initiating cause	**Number of failures**	**Percentage**	**Number of failures**	**Percentage**
Automatic removal by protective device	83	75	11	69
Partial failure, reducing capacity	5	5	0	0
Manual removal	23	20	5	31

5.6.10 Voltage rating

The failure rates for liquid-filled power transformers and rectifier transformers classified by their voltage ratings are shown in Table 14 and Table 15, respectively. An examination of Table 14 reveals the failure rate for the 600 V to 15 000 V transformers (i.e., 0.0052 failures per unit year) is fewer than that for the higher voltage units. The lack of data (i.e., small sample sizes) reported for rectifier transformers makes it impossible to draw any definite conclusions as to the effect of voltage or size on their failure rates.

Table 14—Failure rate versus voltage rating and size for power transformers (1979 survey)

Equipment subclass	Voltage (kV)	Number of units	Sample size (unit-years)	Number of failures	Failure rate (failures per unit-year)
Liquid filled 300 kVA to 10 000 kVA	0.16 to 15	1626	15 775	82	0.0052
Liquid filled 300 kVA to 10 000 kVA	> 15	124	1637	18	0.0110
Liquid filled > 10 000 kVA	> 15	52	490	9	0.0184

Table 15—Failure rate versus voltage rating for rectifier transformers (1979 survey)

Equipment subclass	Voltage (kV)	Number of units	Sample size (unit-years)	Number of failures	Failure rate (failures per unit-year)
All liquid filled	0.16 to 15	65	745	15	0.0201

5.7 1983 IEEE survey on the reliability of large motors

5.7.1 Introduction

A decision was made by the IEEE Motor Reliability Working Group to focus on motors that were of a critical nature in industrial and commercial installations, and thus, only motors larger than 200 hp (149 kW) were selected to be included in the survey (see IEEE Committee Report [B12] and *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 151). Another decision was made to limit the survey to only include motors that were 15 years old or less to focus on motors that were similar to those presently being manufactured and used today.

Failure rates are given for induction, synchronous, wound-rotor, and direct-current motors. Pertinent factors that affect the failure rates of these motors are identified. Data is presented on key variables, such as downtime per failure, failed component, causes of failure, and the time of failure discovery. The results of this recent survey are compared with four other surveys on the reliability of motors (see Albrecht, et al. [B3], Aquillino [B4], IEEE Committee Report [B13], IEEE Std 841-2001 [B19]). Details of the report are shown in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 124. The results of the survey are summarized in 6.5. The term *large motor* is defined in 6.5 to be any motor whose horsepower rating exceeds 200 hp (149 kW).

5.7.2 Overall summary of failure rate for large motors

The 1983 survey included data reported for 360 failures on 1141 motors with a total service of 5085 unit-years. The overall summary of the survey results for induction, synchronous, wound rotor, and direct-current motors is shown in Table 16. Calendar time was used in the calculation of the unit-years of service (rather than the rmming time) to simplify the data collection procedure.

Table 16—Overall summary for large motors above 200 hp (149 kW)[a]

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Median hours down-time per failure
75	5085.0	360	All	0.0708	69.3	16.0
			Induction			
33	1080.3	89	0 V to 1000 V	0.0824	42.5	15.0
52	2844.4	203	1001 V to 5000 V	0.0714	75.1	12.0
5	78.1	2[b]	5001 V to 15 000 V	[b]	[b]	[b]
			Synchronous			
19	459.3	35	1001 V to 5000 V	0.0762	78.9	16.0
2	29.5	3[b]	5001 V to 15 000 V	[b]	[b]	[b]
			Wound-rotor			
5	137.0	10	0 V to 1000 V	0.0730	[b]	[b]
9	251.1	8	1001 V to 5000 V	0.0319	[b]	[b]
2	39.0	4[b]	5001 V to 15 000 V	[b]	[b]	[b]
			Direct current			
5	122.7	6[b]	0 V to 1000 V	[b]	[b]	[b]
1	30.0	—	1001 V to 5000 V	—	—	—

[a] See O'Donnell [B28].
[b] Small sample size; fewer than eight failures.

To summarize the important conclusions derived from the 1983 survey on the failure rates of large motors:

a) Induction and synchronous motors had approximately the same failure rate of 0.07 to 0.08 failures per unit-year.

b) Induction motors rated 0 V to 1000 V and those rated 1001 V to 5000 V had approximately the same failure rates.

c) Wound-rotor motors rated 0 V to 1000 V had a failure rate that was about the same as induction motors of the same rating.

d) Motors with intermittent duty operation had a failure rate that was about half as great as those with continuous duty.

e) Motors with fewer than one start per day had approximately the same failure rate as those motors with between one to 10 starts per day, which would indicate that up to 10 starts per day does not have a major effect on the motor failure rates.

5.7.3 Downtime per failure versus repair/replacement and urgency for repair for large motors

The comparison of the downtime per motor failure data for "repair" versus "replace with spare" is considered important when deciding whether a spare motor should be purchased when designing a new plant. The downtime per failure survey characteristics for all types of motors grouped together as a category is shown in Table 17.

Table 17—Downtime per failure versus repair or replace with spare and urgency for repair—all types of motors above 200 hp (149 kW)[a]

	Number of failures	Average hours (downtime per failure)	Median hours (downtime per failure)
Repair—normal working hours[b]	87	97.7	24.0
Repair—round the clock	45	81.4	72.0
Replace with spare[c]	111	18.2	8.0
Low priority	4[d]	370.0[d]	400.0[d]
Not specified	6[d]	288.0[d]	240.0[d]
Total	251	69.3	14.0

[a] See O'Donnell [B28].
[b] 6570 h for one failure omitted.
[c] 960 h for one failure omitted.
[d] Small sample size; fewer than eight failures.

An examination of Table 17 shows the effect on the repair time that the urgency for repair has had. There were 45 cases of motor failures where the repair activities were carried out on a round-the-clock basis. There were four cases of motor failures where low-priority urgency resulted in a very long downtime; it is important to exclude these cases when making decisions on the design of industrial and/or commercial power systems. In general, the average downtime per failure is about five times larger for repair versus replace with spare.

5.7.4 Failed component—large motors

The identified motor component that failed is shown in Table 18 for induction, synchronous, wound-rotor, and direct-current motors.

Table 18—Failed component—Large motors (above 200 hp [149 kW]) (number of failures)

Failed component[a]	Induction motors	Synchronous motors	Wound rotor motors	Direct-current motors	Total (all types)
Bearings	152	2	10	2	166
Windings	75	16	6		97
Rotor	8	1	4		13
Shaft or coupling	19				19
Brushes or slip ring	—	6	8	2	16
External devices	10	7	1		18
Not specified	40	9		2	51
Total	304	41	29	6	380

[a] Some respondents reported more than one failed component per motor failure.

It can be seen that the two largest categories reported are motor bearing and winding failures with 166 and 97 failures, respectively, out of a total of 380 failures. Bearings and windings represent 44% and 26%, respectively, of the total number of motor failures.

5.7.5 Failed component versus time of discovery—large motors

Data on the failed component versus the time the failure was discovered is shown in Table 19. It can be seen that 60.5% of the failures found during maintenance or test are bearings. Many users consider that it is very important to find as many failures as possible during maintenance or test rather than normal operation. Bearings and windings represent 36.6% and 33.1%, respectively, of the failures discovered during normal operation.

Table 19—Failed component versus time of discovery (all types of motors above 200 hp [149 kW]) (percentage of failures)

	Time of discovery		
Failed component	**Normal operation**	**Maintenance or test**	**Other**
Bearing	36.6	60.5	50.0
Windings	33.1	8.3	28.6
Rotor	5.1	1.8	0.0
Shaft or coupling	5.8	8.3	14.3
Brushes or slip rings	3.1	7.3	0.0
External devices	5.0	3.7	0.0
Not specified	11.3	10.1	7.1
Total percentage of failures	100.0	100.0	100.0
Total number of failures	257	109.0	14.0

5.7.6 Causes of large motor bearing and winding failures

The causes of motor failures categorized according to the failure initiator, the failure contributor, and the failure's underlying cause are shown in Table 20 for induction, synchronous, and all motors.

Table 20—Causes of failure versus motor type and versus bearing and winding failures—motors above 200 hp (149 kW) (percentage of failures)

All motor types—failed component		All types of motors %	Induction motors %	Synchronous motors %	Causes of failures
Bearings %	Windings %				
					Failure initiator
0.0	4.1	1.5	1.4	0.0	Transient overvoltage
12.4	21.4	13.2	14.7	0.0	Overheating
1.9	36.7	12.3	11.9	21.1	Other insulation breakdown
50.3	10.2	33.1	37.4	5.2	Mechanical breakage
3.7	11.2	7.6	5.8	23.7	Electrical fault or malfunction
0.0	2.1	0.9	0.7	2.6	Stalled motor
31.7	14.3	31.4	28.1	47.4	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
161.0	98.0	341.0	278.0	38.0	Total number of failures
					Failure contributor
1.4	6.5	4.2	4.9	2.7	Persistent overheating
0.7	7.6	3.0	3.4	0.0	High ambient temperature
2.7	18.5	5.8	6.7	2.7	Abnormal moisture
0.0	5.4	1.5	1.5	2.7	Abnormal voltage
0.0	1.1	0.6	0.7	0.0	Abnormal frequency
21.8	8.7	15.5	17.6	5.4	High vibration
5.4	6.5	4.2	4.5	2.7	Aggressive chemicals
31.3	5.4	15.2	16.9	8.1	Poor lubrication
0.0	7.6	3.9	2.2	2.7	Poor ventilation or cooling
20.4	18.5	26.4	24.0	51.4	Normal deterioration from age
16.3	14.2	19.7	17.6	21.6	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
147.0	92.0	330.0	267.0	37.0	Total number of failures
					Failure underlying cause
17.8	10.9	20.1	20.3	22.2	Defective component
14.5	10.9	12.9	15.9	0.0	Poor installation/testing
27.6	19.6	21.4	22.8	11.1	Inadequate maintenance
2.0	6.5	3.6	3.3	2.8	Improper operation
0.7	0.0	0.6	0.8	0.0	Improper handling/shipping
7.9	7.6	6.1	6.5	2.8	Inadequate physical protection
2.6	15.2	5.8	5.3	11.1	Inadequate electrical protection
7.2	5.4	6.8	5.7	5.6	Personnel error
2.0	3.3	3.9	2.8	13.9	Outside agency—not personnel
5.9	4.3	4.9	4.9	0.0	Motor-driven equipment mismatch
11.8	16.3	13.9	11.7	30.5	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
152.0	92.0	309.0	246.0	36.0	Total number of failures

Mechanical breakage is the largest failure initiator for induction motors. Normal deterioration from age, high vibration, and poor lubrication are the major failure contributors to induction motor failures. Inadequate maintenance and defective component are the largest underlying causes of induction motor failures.

Electrical fault or malfunction and other iusulation breakdown are the major failure initiators for synchronous motors. Normal deterioration from age is the major fault contributor of synchrouous motors. Defective component is the largest underlying cause of synchronous motor failures.

Table 20 shows a correlation between bearing failures and the causes of failure: 50.3% of bearing failures were initiated by mechanical breakage; 31.3% and 21.8%, respectively, had poor lubrication and high vibration as failure contributors; and 27.6% blamed inadequate maintenance as the underlying cause.

Table 20 also shows a correlation between winding failures and the causes of failure: 36.7% of the winding failures had other insulation breakdown as the initiator; 18.5% and 18.5%, respectively, had normal deterioration from age and abnormal moisture as failure contributors; 19.6% had inadequate maintenance and 15.2% had inadequate electrical protection as the underlying cause.

It is of interest to note that inadequate maintenance was the largest underlying cause of both bearing aud winding failures. A special study of the 71 failures attributed to inadequate maintenance is shown in Table 21. It can be clearly seen that 59.1% of the motor components that failed were beariugs, 52.1% of the failures were initiated by mechanical breakage, and 43.7% of the failures had poor lubrication as a failure contributor.

Table 21 —Failures caused by inadequate maintenance versus failed component, failure initiator, and failure contributor (all types of motors above 200 hp [149 kW])[a]

Percentage	Failed component
59.1	Bearing
25.4	Winding
1.4	Rotor
0.0	Shaft or coupling
8.5	Brushes or slip rings
1.4	External device
4.2	Other
100.0	Total percentage (number of failures = 71)
	Failed initiator
0.0	Transient overvoltage
4.2	Overheating
14.1	Other insulation breakdown
52.1	Mechanical breakage
2.8	Electrical fault or malfunction
0.0	Stalled motor
26.8	Other
100.0	Total percentage (number of failures = 71)
	Failed contributor
0.0	Persistent overloading
4.2	High ambient temperature
7.0	Abnormal moisture
0.0	Abnormal voltage
0.0	Abnormal frequency
4.2	High vibration
9.9	Aggressive chemical
43.7	Poor lubrication
1.4	Poor ventilation/cooling
18.3	Normal deterioration from age
11.3	Other
100.0	Total percentage (number of failures = 71)

[a] See O'Donnell [B28].

5.7.7 Other significant results

5.7.7.1 Introduction

Several additional parameters were reported in O'Donnell [B28] in terms of their effect on the failure rate of motors above 200 hp (149 kW). These included the effect of horsepower, speed, enclosure, environment, duty cycle, service factor (S.F.), average number of starts per day, grounding practice, maintenance quality, maintenance cycle, type of maintenance performed, and months since last maintenance prior to the failure.

Some combinations of these parameters, two at a time, have also been studied and reported (see O'Donnell [B28]).

5.7.7.2 Open versus enclosed motors

The following significant conclusions were reached:

a) Open motors had a higher failure rate than weather-protected or enclosed motors.

b) Outdoor motors had a lower failure rate than indoor motors because most outdoor motors were weather protected or enclosed, and most indoor motors were open.

5.7.7.3 Service factor

The 1.15 S.F. induction motors had a higher reported failure rate than 1.0 S.F. induction motors, but the opposite was true for synchronous motors.

5.7.7.4 Speed and horsepower

The failure rate for induction motors did not vary significantly among the three speed categories (i.e., 0 RPM to 720 RPM, 721 RPM to 1800 RPM, and 1801 RPM to 3600 RPM). The highest failure rate was in the middle speed category, while the lowest failure rate was in the higher speed category. The 201 hp (150 kW) to 500 hp (373 kW) induction motors had approximately the same failure rate as 501 hp (374 kW) to 5000 hp (3730 kW) induction motors in each of the three speed ranges studied.

Synchronous motors in the speed category 0 RPM to 720 RPM had a higher failure rate than synchronous motors in the 721 RPM to 1800 RPM category. There were no respondents for the 1801 RPM to 3600 RPM category.

5.7.8 Data supports chemical industry motor standard

Reliability data for induction motors from both the 1983 IEEE survey and the 1973-1974 IEEE survey (see *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, pages 1 and 61) supported the need for several of the features incorporated into IEEE Std 841-2001 [B19]. The IEEE surveys show the need for improved reliability of bearings and windings and, in some cases, the need for better physical protection against aggressive chemicals and moisture. Some of the more significant recommendations for an IEEE Std 841-2001 [B19] motor include:

a) Totally enclosed fan-cooled (TEFC) enclosure

b) Maximum 80 °C rise at 1.0 S.F.

c) Contamination protection for bearings and grease reservoirs

d) Three-year continuous L-10 bearing life

e) Maximum bearing temperature of 45 °C rise (50 °C rise on two-pole motors)

f) Cast iron frame construction

g) Nonsparking fan

h) Single connection point per phase in terminal box

i) Maximum sound power level of 90 dBA

j) Corrosion-resistant paint, internal joints and surfaces, and hardware

IEEE Std 841-2001 [B19] was tailored for the petroleum/chemical industry; however, it can be beneficial for other industries with similar requirements.

5.7.9 Comparison of 1983 motor survey with other motor surveys

5.7.9.1 Introduction

One of the primary purposes of comparing the results of 1983 motor survey with previous surveys and other surveys (see Albrecht, et al. [B2], [B3], and the "Summary of Replies to the 1982 Technical Questionnaire" [B40]) is to attempt to identify trends in the failure characteristics of motors (i.e., changing failure rates with time, varying causes of motor failures, assessing the impact of maintenance practices).

5.7.9.2 1983 EPRI and 1983-1985 IEEE surveys

The size and scope of the IEEE Working Group and EPRI motor surveys is shown in Table 22. The motor failure rate of 0.035 failures per unit-year in the EPRI-sponsored study of the electric utility industry is about half the IEEE failure rate of 0.0708 failures per year.

Table 22—Size and scope comparison of IEEE1983-1985 motor survey and EPRI-sponsored motor survey in electric utility power plants[a]

Parameter	IEEE Working Group	EPRI Phase I
Horsepower (kilowatts)	> 200 (149 kW)	100 (75 kW) and up
Number of companies/utilities	33	56
Number of plants or units	75	132
Number of motors	114 100	47 970
Total population (unit-years)	508 500	24 914 100
Total failures	3600	871 100
Failure rate (all motors)	0.07 080	0.03 500[b]

[a] See O'Donnell [B28].
[b] To first failure.

The percentage of motor failures classified by component in the two surveys is shown in Table 23. Similar results were obtained in these two studies on the failed component, with bearing, winding, and rotor-related percentages that were each about the same.

Table 23—Failure by component comparison of the IEEE 1983-1985 motor survey and EPRI-sponsored survey

IEEE Working Group	EPRI Phase I
44% bearings	41% bearing related
26% windings	37% stator related
8% rotor/shafts/couplings	10% rotor related

Table 24 shows some differences between the two studies on the causes of failures. The IEEE survey found inadequate maintenance, poor installation/testing, and misapplication to be a significantly larger percentage of the causes of motor failures, while the EPRI study attributed a larger percentage to the manufacturer. In addition, the EPRI study had a much larger percentage of failures attributed to other, or not specified, causes. Additional results from the EPRI-sponsored study were given in a later paper (see Albrecht, et al. [B3]).

Table 24—Cause of failure comparison—IEEE 1983-1985 motor survey and EPRI-sponsored motor survey

Failure cause	EPRI Phase I		IEEE Working Group		Failure cause
	Number	Percent	Number	Percent	
Manufacturer design workmanship	401	32.8	62	17.2	Defective component
Misoperation	124	10.2	32	8.9	Improper operation/personnel error
Misapplication	83	6.8	52	14.5	Misapplication, motor-driven equipment mismatch, inadequate electrical protection, inadequate physical protection
			66	18.3	Inadequate maintenance
			40	11.1	Poor installation/testing
			12	3.3	Outside agency other than personnel
			2	0.6	Improper handling/shipping
Other or not specified	613	50.2	94	26.1	Other or not specified
Total failures	1221	100.0	360	100.0	Total failures

5.7.9.3 1982 Doble data and 1983-1985 IEEE surveys

A 1982 Doble survey (see "Summary of Replies to the Technical Questionnaire" [B40]) in the electric utility industry (for motors 1000 hp [746 kW] and up and not over 15 years of age) reported 68 insulation-related failures in 2078 unit-years of service during the year 1981. This gives an insulation-related failure rate of 0.033 failures per unit-year. This can be compared with a winding failure rate of 26% times 0.0708, which equals 0.018 failures per unit-year that can be calculated from the 1983-1985 IEEE survey of motors above 200 hp (149 kW) and not older than 15 years, shown in Table 22 and Table 23.

5.7.9.4 IEEE surveys 1973-1974 and 1983-1985

Table 25 shows the results from the 1973-1974 IEEE motor reliability survey of industrial plants (see IEEE Committee Report [B13]). This survey covered motors 50 hp (37.3 kW) and larger, and had no limit on the age of the motor. Those results can be compared to Table 16 for the 1983-1985 IEEE survey of motors above 200 hp (149 kW) and not older than 15 years. The 1983-1985 failure rates of induction motors and synchronous motors were about double those from the 1973-1974 survey for motors 601 V to 15 000 V.

Table 25—1973-1974 IEEE overall summary for motors 50 hp (37.3 kW) and larger

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Median hours down-time per failure
—	42 463	561	All	0.0132	111.6	—
17	19 610	213	Induction, 0 V to 600 V	0.0109	114.0	18.3
17	4229	172	Induction, 5001 V to 15 000 V	0.0404	76.0	153.0
2	13 790	10	Synchronous, 1001 V to 5000 V	0.0007	35.3	35.3
11	4276	136	Synchronous, 5001 V to 15 000 V	0.0318	175.0	153.0
6	558	310	Direct current	0.0556	37.5	16.2

5.7.9.5 AIEE 1962 and 1983-1985 IEEE surveys

Table 26 shows the results from the 1962 AIEE motor reliability survey of industrial plants. This survey covered motors 250 hp (187 kW) and larger and had no limit on the age of the motor. The failure rates for both induction motors and synchronous motors from the 1962 AIEE survey are within 30% of those shown in Table 16 for the 1983-1985 IEEE survey of motors above 200 hp (149 kW) and not older than 15 years. The two surveys conducted 21 years apart show remarkably similar results.

Table 26—AIEE overall summary for motors 250 hp (187 kW) and larger, United States and Canada, 1962

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Median hours down-time per failure
46	1420	140	Induction	0.0986	78.0	70.0
53	600	31	Synchronous	0.0650	149.0	68.0

5.7.9.6 1994 IEEE PES survey of overhead transmission lines

The IEEE Power Engineering Society conducted an extensive survey of the outages of overhead transmission lines 230 kV and above in the United States and Canada (see Adler, et al. [B1]). This is included as *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 258 and covers 230 kV, 345 kV, 500 kV, and 765 kV and includes both permanent and momentary outages. Line-caused outages have been separated from terminal-caused outages. Data are given on the type of fault that caused the outage. Faults can resnlt in voltage sags at the entrance to industrial and commercial installations.

6. Part 3: Equipment reliability surveys conducted prior to 1976

6.1 Introduction

From 1973 to 1975, the Power Systems Reliability Subcommittee of the IEEE Industrial Power Systems Department conducted and published surveys of electrical equipment reliability in industrial plants (see IEEE Committee Reports [B11], [B13]) including circuit breakers, motor starters, disconnect switches, bus duct, open wire, cable, cable joints, and cable terminations. Those reliability surveys of electrical equipment and electric utility power supplies were extensive, collecting data such as:

a) Failure rate

b) Failure duration

c) Failure modes

d) Causes of failure

e) Failure repair method and failure repair urgency

f) Loss of motor load versus time of power outage

The section also discusses the maximum length of time of an interruption of electrical service that will not stop plant production, plant restart time after service is restored following a failure that caused a complete plant shutdown, and the cost of power interruptions to industrial plants and commercial buildings. In addition, the data show multiple utility interdependence and equipment failure versus quality of maintenance.

The preceding data was taken from the IEEE surveys of industrial plants (see Albrecht, et al. [B3] and the "Report of Equipment Availability for a 10 Year Period" [B33]) and commercial buildings (see O'Donnell [B28]). The detailed reports are given in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, pages 1, 61, 87, and 95. A later survey (IEEE Committee Report [B13]) of the reliability of switchgear bus is included in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*. More recent surveys on transformers, large motors, cable, terminations, and splices are included in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, pages 114, 124, and 151, respectively. Recent surveys on circuit breakers are shown in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, pages 161 and 170. A 1989 survey on diesel and gas turbine generating units is included in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 187.

Clause 7 presents data for specific types of equipment according to Table 27.

Table 27 —Part 3 equipment reliability table reference guide

Electrical equipment type		Surveys prior to 1976
Motors	> 50 hp (37.3 kW)	Table 35
	> 200 hp (149 kW)	Table 35
	> 250 hp (187 kW)	Table 35
Motor starters		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Generators		0
Transformers	Power	Table 35, Table 36
	Rectifier	Table 35, Table 36
Circuit breakers		Table 28, Table 29, Table 31, Table 32, Table 33 Table 35, Table 36
Disconnect switches		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Bus duct		Table 30, Table 31, Table 32, Table 33, Table 35
Switch gear	Bus insulated	Table 35
	Bus bare	Table 35
Open wire		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Cable		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Cable joints		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Cable terminations		Table 30, Table 31, Table 32, Table 33, Table 35, Table 36
Electric utility power supplies		Table 34, Table 35

6.2 Reliability of electrical equipment (1974 survey)

6.2.1 Introduction

In compiling the data for the 1974 survey, a failure was defined as any trouble with a power system component that causes any of the following effects:

a) Partial or complete plant shutdown or below-standard plant operation

b) Unacceptable performance of user's equipment

c) Operation of the electrical protective relaying or emergency operation of the plant electric system

d) De-energization of any electric circuit or equipment

A failure on a public utility supply system may cause the user to have either of the following:

— A power interruption or loss of service

— A deviation from normal voltage or frequency outside the normal utility profile

All of the electrical equipment categories listed in this section have eight or more failures. This is considered an adequate sample size (see Patton [B32]) in order to have a reasonable chance of determining a failure rate within a factor of 2. Failure rate and average downtime per failure data for an additional six categories of equipment are contained in IEEE Committee Report [B13] (*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 1).

6.2.2 Failure modes of circuit breakers

6.2.2.1 Introduction

The failure modes of metal-clad drawout and fixed-type circuit breakers are shown in Table 28. Of primary concern to industrial plants is the large percentage of circuit breaker failures (i.e., 42%) that opened when they should not. This type of circuit breaker failure can significantly affect plant processes and may result in a total plant shutdown. Also, a large percentage (32%) of the circuit breakers failed while in service (not while opening or closing). *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, pages 161 and 170, and the "Report on Power Circuit Troubles—1975" [B39] contain additional circuit breaker reliability information.

Table 28—Failure modes of circuit breakers[a] (1974 survey)

All circuit breakers %	Metal-clad drawout			Fixed-type[b]		Failure characteristics
	All %	0 V to 600 V 601 V to 15 000 V %	All sizes %	0 V to 600 V, all sizes %	All %	
5	5	2	7	8	6	Failed to close when it should
9	12	21	0	0	2	Failed while opening
42	58	49	71	5	4	Opened when it should not
7	6	4	9	5	4	Damaged while successfully opening
2	1	0	0	0	4	Damaged while closing
32	16	24	10	77	32	Failed while in service (not while opening or closing)
1	0	0	0	0	2	Failed during testing or maintenance
1	2	0	3	0	0	Damage discovered during testing or maintenance
1	0	0	0	5	5	Other
100	100	100	100	100	100	Total percentage
166	117	53	59	39	48	Number of failures in total percentage
8	7	0	7	1	1	Number not reported
173	124	53	66	40	49	Total failures

[a] *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 170 contains some limited data from a later IEEE survey. *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 161 contains data for circuit breakers above 63 kV from a CIGRE 13-06 worldwide survey with a very large population.
[b] Includes molded case.

6.2.2.2 Trip units on low-voltage breakers

Most modern low-voltage power circuit breakers are purchased with a solid-state trip unit rather than an electromechanical trip unit. Many older low-voltage breakers have been retrofitted with a solid-state trip that replaced an electromechanical trip unit. A comparison has been made of the reliability of these two types of trip units based on a 1996 IEEE survey of low-voltage breaker operation as found during mainteuauce (see O'Donnell [B30]).

Electromechanical trip units had an unacceptable operation about twice as often as solid-state units. A summary of the most important results is given in Table 29. The complete results are included in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 266.

Table 29—Survey of low-voltage power breaker operation as found during maintenance tests—electromechanical versus solid-state trip type unit; new solid state units versus used (older) solid state units

	Trip unit type			
	Electromechanical		Solid-state	
	Number of failures	%	Number of failures	%
Unacceptable operation				
Trip unit failed to operate	81	7.7	28	3.0
Trip unit out of specification	60	5.7	24	2.6
Mechanical operations (springs, arms/levers, hardened lubricant)	26	2.5	19	2.0
Power contacts (alignment, incorrect pressure, pitted)	25	2.4	19	2.0
Arc chutes (clean, replace/repair, chipped)	6	0.6	6	0.7
Auxiliary contacts	4	0.4		
Total unacceptable	204	19.4%	100	10.7%
Acceptable operation	850	80.6%	835	89.3%
Total number of tests	1054	100.0%	935	100.0%

6.2.2.3 Failure characteristics of other electrical equipment

The failure characteristics of electrical equipment (excluding transformers and circuit breakers) are shown in Table 30. The dominant failure characteristic for this equipment is that it failed in service. A large percentage of the damage to motor starters (36%), disconnect switches (18%), and cable terminations (12%) was discovered during testing or maintenance.

Table 30—Failure characteristics of other electrical equipment

Motor starters %	Disconnect switches %	Bus duct %	Open wire %	Cable %	Cable joint %	Cable terminations %	Failure characteristics
37	72	90	68	92	96	80	Failed in service
6	3	5	2	2	4	2	Failed during testing or maintenance
36	18	0	1	2	0	12	Damage discovered during testing or maintenance
20	6	5	6	3	0	6	Partial failure
2	1	0	23	1	0	0	Other

6.2.2.4 Causes and types of failures of electrical equipment

Table 31 shows the breakdown of the reported failures by damaged parts and failure type.

Table 31 —Failure, damaged part, and failure type (1974 survey)

Circuit breakers %	Motor starters %	Disconnect switches %	Bus duct %	Open wire %	Cable %	Cable joints %	Cable terminations %	Failure, damaged part
0	5	0	15	0	5	0	0	Insulation—winding
2	0	1	10	1	0	0	12	Insulation—bushing
19	10	14	65	6	83	91	74	Insulation—other
1	0	0	0	0	3	0	0	Mechanical—bearings
11	16	9	0	0	0	0	0	Mechanical—other moving parts
6	2	30	0	4	1	0	4	Mechanical—other
6	13	8	0	3	1	0	0	Other electric—auxiliary device
28	2	1	0	3	1	0	0	Other electric—protective device
1	0	0	0	0	0	0	0	Tap changer—no load type
0	0	0	0	0	0	0	0	Tap changer—load type
26	52	37	10	83	6	9	10	Other
								Failure type
33	14	15	70	34	73	70	55	Flashover or arcing involving ground
10	20	4	30	23	1	9	4	All other flashover or arcing
19	55	47	0	25	7	20	37	Other electric defects
11	11	14	0	6	5	0	4	Mechanical defect
27	0	20	0	12	14	0	0	Other

The data presented in Table 32 indicate that the respondents suspected inadequate maintenance and manufacturer-defective components were responsible for a significant percentage of the reported failures.

Table 32—Suspected failure responsibility, failure-initiating cause, and failure-contributing cause

Circuit breakers %	Motor starters %	Disconnect switches %	Bus duct %	Open wire %	Cable %	Cable joints %	Cable terminations %	Suspected failure responsibility
23	18	29	26	0	16	0	0	Manufacturer-defective component
0	0	0	0	0	0	0	0	Transportation to site—defective handling
4	51	6	16	2	8	0	18	Application engineering—improper application
3	0	4	5	9	14	50	38	Inadequate installation and testing prior to startup
23	8	13	16	30	10	18	32	Inadequate maintenance
6	3	39	0	2	3	0	0	Inadequate operating procedures
5	0	1	5	5	4	5	0	Outside agency—personnel
1	0	0	0	211	6	2	8	Outside agency—other
35	20	8	32	31	39	25	14	Other
								Failure-initiating cause
4	0	8	6	0	0	0	0	Persistent overloading
1	0	3	0	0	0	2	0	Above-normal temperature
0	0	1	0	0	0	0	0	Below-normal temperature
2	0	0	0	28	14	13	10	Exposure to aggressive chemicals or solvents
0	0	0	17	1	8	22	12	Exposure to abnormal moisture or water
0	0	0	0	3	2	0	0	Exposure to nonelectrical fire or burning
0	0	0	0	0	1	0	0	Obstruction of ventilation by objects or material
17	40	5	49	3	30	29	24	Normal deterioration from age
1	0	0	11	30	16	2	16	Severe wind, rain, snow, sleet, or other weather conditions
2	0	0	0	1	0	0	0	Protective relay improperly set
1	2	0	0	0	0	0	0	Loss or deficiency

Circuit breakers %	Motor starters %	Disconnect switches %	Bus duct %	Open wire %	Cable %	Cable joints %	Cable terminations %	Suspected failure responsibility
23	18	29	26	0	16	0	0	Manufacturer-defective component
0	0	0	0	0	0	0	0	Transportation to site—defective handling
4	51	6	16	2	8	0	18	Application engineering—improper application
3	0	4	5	9	14	50	38	Inadequate installation and testing prior to startup
23	8	13	16	30	10	18	32	Inadequate maintenance
6	3	39	0	2	3	0	0	Inadequate operating procedures
5	0	1	5	5	4	5	0	Outside agency—personnel
1	0	0	0	211	6	2	8	Outside agency—other
35	20	8	32	31	39	25	14	Other
								of lubricant
0	0	0	0	0	0	0	0	Loss or deficiency of oil or cooling medium
10	3	0	6	2	3	0	8	Misoperation or testing error
3	1	26	0	2	1	0	0	Exposure to dust or other contaminants
56	54	54	11	30	24	32	30	Other

6.2.2.5 Failure repair method and failure repair urgency

The failure repair method and the failure repair urgency had a significant effect on the average downtime per failure. Table 33 shows the percent of the time that different repair methods and urgencies occurred. A special study on this subject is reported in Tables 50, 51, 55, and 56 of Patton [B32] (*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 61) for circuit breakers and cables.

Table 33—Failure repair method and failure repair urgency (1974 survey)

Circuit breaker %	Motor starters %	Disconnect switches %	Bus duct %	Open wire %	Cable %	Cable joints %	Cable terminations %	Failure repair method
51	33	30	66	70	47	87	60	Repair of failed component in place or sent out for repair
49	67	70	35	9	53	13	34	Repair by replacement of failed component with spare
0	0	0	0	21	0	0	0	Other
								Failure repair urgency
73	66	20	80	55	66	56	53	Requiring round-the-clock all-out efforts
22	34	80	15	26	28	22	31	Requiring repair work only during regular workday, perhaps with overtime
5	0	0	5	0	6	22	16	Requiring repair work on a non-priority basis
0	0	0	0	19	0	0	0	Other

6.2.2.6 Reliability of electric utility power supplies to industrial plants

The failure rate and the average downtime per failure of electric utility supplies to industrial plants are given in Table 34. Additional details are given in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, and page 95 of the paper "Report on Equipment Availability for 10 Year Period 1965-74" [B33]. A total of 87 plants participated in the IEEE survey covering the period from 1 January 1968 through October 1974.

Table 34—IEEE survey of reliability of electric utility supplies to industrial plants (IEEE Committee report, 1975 survey)

	Failures per unit-year[a]			Average duration (minutes per failure)[a]		
	$\lambda\Sigma$	λP	λ	rS	rR	r
Single-circuit utility supplies						
Voltage level						
$V \leq 15$ kV	0.905	2.715	3.621	3.5	165	125
15 kV $< V \leq 35$ kV		1.657	1.657		57	57
$V > 35$ kV	0.527	0.843	1.370		59	37
All	0.556	1.400	1.956	2.3	110	79
Multiple-circuit utility supplies (all voltage levels)						
Switching scheme						
All breakers closed	0.255	0.057	0.312	8.5	130	31
Manual throw-over	0.732	0.118[b]	0.850	8.1	84[b]	19
Automatic throw-over	1.025	0.171	1.196	0.6	96	14
All	0.453	0.085	0.538	5.2	110	22
Multiple-circuit utility supplies (all switching schemes)						
Voltage level						
$V \leq 15$ kV	0.640	0.148	0.788	4.7	149	32
15 kV $< V \leq 35$ kV	0.500	0.064[b]	0.564	4.0	115[b]	17
$V > 35$ kV	0.357	0.067	0.424	6.1	184	34
Multiple-circuit utility supplies (all circuit breakers closed)						
Voltage level						
$V \leq 15$ kV	0.175	0.088[b]	0.263	0.7	335[b]	112
15 kV $< V \leq 35$ kV	0.342	0.019[b]	0.361	7.0	120[b]	13
$V > 35$ kV	0.250	0.061	0.311	11.0	203	49

[a] Failure rates λS and λR and average durations rS and rR are, respectively, rates and durations of failures terminated by switching and by repair or replacement. Unsubscripted rates and durations are overall values.
[b] Small sample size; fewer than eight failures.

The survey results shown in Table 34 have distinguished between power failures that were terminated by a switching operation and those requiring repair or replacement of equipment. The latter have a much longer outage duration time. Some of the conclusions that can be drawn from the IEEE data are:

a) The failure rate for single-circuit supplies is about 6 times that of multiple-circuit supplies that operate with all circuit breakers closed, and the average duration of each outage is about 2.5 times as long.

b) Failure rates for multiple-circuit supplies that operate with either a manual or an automatic throw-over scheme are comparable to those for single-circuit supplies, but throw-over schemes have a smaller average failure duration than single-circuit supplies.

c) Failure rates are highest for utility supply circuits operated at distribution voltages and lowest for circuits operated at transmission voltages (greater than 35 kV).

It is important to note that the data in Table 34 shows that the two power sources of a double-circuit utility supply are not completely independent. This is analyzed in an example, where (for the one case analyzed) the actual failure rate of a double-circuit utility supply is more than 200 times larger than the calculated value for two completely independent utility power sources.

Utility supply failure rates vary widely in various locations. One of the significant factors in this difference is believed to be different exposures to lightning storms. Thus, average values for the utility supply failure rate may not be appropriate for use at any one location. Local values should be obtained, if possible, from the utility involved, and these values should be used in reliability and availability studies.

An earlier IEEE reliability survey of electric power supplies to industrial plants was published in 1973 and is reported in Table 3 of Albrecht, et al. [B3] (*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 1). The earlier survey had a smaller database and is not believed to be as accurate as the one summarized in Table 35.

6.2.2.7 Method of electrical service restoration to plant

The 1973-1975 IEEE data on method of electrical service restoration to plant is shown in Table 35.

The most common methods of service restoration to a plant are replacement of a failed component with a spare or the repair of the failed component. The primary selection or secondary selection is used only 22% of the time. This would indicate that most power distribution systems in this IEEE survey were radial.

Table 35—Method of service restoration (1974 survey)

Total	Electric utilities power supplies	Trans-formers	Circuit breakers	Motor starters	Motors	Generators	Disconnect switches	Switch gear bus: Insulated	Switch gear bus: Bare	Bus duct	Open wire	Cable	Cable joints	Cable terminations	Method of service restoration
7%	1%	3%	6%	0%	5%	20%	0%	58%	25%	20%	13%	14%	28%	19%	Primary selective—manual
2%	8%	0%	1%	0%	0%	0%	0%	0%	5%	0%	4%	5%	8%	0%	Primary selective—automatic
11%	1%	25%	6%	0%	14%	33%	0%	17%	10%	10%	2%	20%	32%	23%	Secondary selective—manual
2%	1%	3%	8%	0%	0%	0%	0%	0%	0%	0%	1%	0%	8%	4%	Secondary selective—automatic
0+%	0%	0%	0%	0%	0%	0%	0%	0%	5%	0%	0%	0%	0%	0%	Network protector operation—automatic
22%	5%	25%	11%	12%	30%	20%	3%	17%	20%	35%	31%	42%	24%	27%	Repair of failed component
22%	2%	39%	38%	10%	29%	14%	77%	0%	10%	35%	6%	2%	0%	12%	Replacement of failed component
12%	81%	0%	1%	0%	0%	13%	0%	0%	0%	0%	1%	1%	0%	0%	Utility service restored
22%	1%	5%	29%	78%	22%	0%	20%	8%	25%	0%	42%	16%	0%	15%	Other
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	Total %
1204	171	75	160	68	318	15	69	12	20	20	103	122	25	25	Total number reported

6.2.2.8 Equipment failure rate multiplier versus maintenance quality

The relationship between maintenance practice and equipment failures for transformers, circuit breakers, and motors is discussed in detail in IEEE Std 3006.4. These multipliers were determined in a special study (Part 6 of Patton [B32]) (*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 61). The failure rate of motors is very sensitive to the quality of maintenance.

The percentage of failures due to inadequate maintenance versus the time since maintained is given in IEEE Std 3006.4 for circuit breakers, motors, open wire, transformers, and all electrical equipment classes combined. A high percentage of electrical equipment failures were blamed on inadequate maintenance if there had been no maintenance for more than two years prior to the failure.

6.2.2.9 Reliability improvement of electrical equipment in industrial plants between 1962 and 1973

The failure rates for electrical equipment (except for motor starters) in industrial plants appeared to have improved considerably during the 11-year interval between the 1962 AIEE reliability survey (see Dickinson [B6]) and the 1973-1974 IEEE reliability survey (see IEEE Committee Report [B13]). Table 36 shows how much the failure rates had improved for several equipment categories. These data are calculated from a 1974 report (Albrecht, et al. [B2]). In 1962, circuit breakers had failure rates that were 2.5 to 6.0 times higher than those reported in 1973. The largest improvements in equipment failure rates have occurred on cables and circuit breakers. The authors discussed some of the reasons for the failure rate improvements during the 11-year interval. It would appear that manufacturers, application engineering, installation engineering, and maintenance personnel have all contributed to the overall reliability improvement.

Table 36—Failure rate improvement factor of electrical equipment in industrial plants during the 11-year interval between the 1962 AIEE survey and the 1973 IEEE survey

Equipment category	Failure rate ratio AIEE (1962) IEEE (1973)
Cable	
Nonleaded in underground conduit	9.7
Nonleaded, aerial	5.8
Lead covered in underground conduit	3.4
Nonleaded in aboveground conduit	1.6
Cable joints and terminations	
Nonleaded	5.3
Leaded	2.0
Circuit breakers	
Metal-clad drawout, 0 V to 600 V	6.0
Metal-clad drawout, above 600 V	2.9
Fixed 2.4 kV to 15 kV	2.5
Disconnect switches	
Open, above 600 V	3.4
Enclosed, above 600 V	1.6
Open wire	3.4
Transformers	
Below 15 kV, 0 kVA to 500 kVA[a]	2.0
Below 15 kV, above 500 kVA	2.0
Above 15 kV	1.6
Motor starters, contactor type	
0 V to 600 V	1.3
Above 600 V	1.3

[a] 300 kVA to 750 kVA for 1973.

The authors also make a comparison between the snrveys of the actual downtime per failure for all the equipment categories shown in the table in IEEE Committee Report [B13]. In general, the actual downtime per failure was larger in 1973 than in 1962.

6.2.2.10 Loss of motor load versus time of power outage

A special study was reported in Table 47 of IEEE Committee Report [B13] (*Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 61) on loss of motor load versus duration of power outages. When the duration of power outages is longer than 10 cycles, most plants lose motor load. However, when the duration of power outages is between one and 10 cycles, only about one-third of the plauts lose their motor load.

Test results of the effect of fast bus transfers on load continuity are reported in Averill [B5]. This includes 4 kV iuduction and synchronous motors with the following type of loads:

a) Forced draft fan

b) Circulating water pump

c) Boiler feed booster pump

d) Condensate pump

e) Gas recirculation fan

A list of prior papers on the effect of fast bus transfer on motors is also contained in Albrecht, et al. [B3].

6.2.2.11 Critical service loss duration time

What is the maximum length of time that an interruption of electrical service will not stop plant production? The median value for all plants is 10.0 s. See Table 2-3 in IEEE Std 3006.2-2016 for a summary of the IEEE survey of industrial plants.

What is the maximum length of time before an interruption to electrical service is considered critical in commercial buildings? The median value of all commercial buildings is between 5 min and 30 min. See Table 2-3 in IEEE Std 3006.2-2016 for a summary of the IEEE survey of commercial buildings.

6.2.2.12 Plant restart time

What is the plant restart time after service is restored following a failure that has caused a complete plant shutdown? The median value for all plants is 4.0 h. See Table 2-4 in IEEE Std 3006.2-2016 for a summary of the IEEE survey of industrial plants.

6.2.2.13 Other sources of reliability data

The reliability data from industrial plants that are summarized are based upon IEEE Committee Report [B16], which was published during 1973-1975. Dickinson's report [B6] is an earlier reliability survey of industrial plants that was published in 1962.

Many sources of reliability data on similar types of electrical equipment exist in the electric utility industry. The Edison Electric Institute (EEI) has collected and published reliability data on power transformers, power circuit breakers, metal-clad switchgear, motors, excitation systems, and generators (see EEI Publications [B33], [B34], [B35], [B36], [B37], [B38], [B39]). Most EEI reliability activities do not collect outage duration time data. The North American Electric Reliability Council (NERC) collects and publishes reliability and availability data on generation prime mover equipment.

Failure rate data and outage duration time data for power transformers, power circuit breakers, and buses are given in Patton [B32]. These data have come from electric utility power systems.

Very little other published data is available on failure modes of power circuit breakers and on the probability of a circuit breaker not operating when called upon to do so. An extensive worldwide reliability survey of the major failure modes of power circuit breakers above 63 kV on utility power systems has been made by the CIGRE 13-06 Working Group as shown in *Historical Reliability Data for IEEE 3006 Standards: Power System Reliability*, page 161. Failure rate data and failure per operating cycle data have been determined for each of the major failure modes. Outage duration time data has also been collected. In addition, data has been collected on the costs of scheduled preventive maintenance; this includes the hours of labor per circuit breaker per year and the cost of spare parts consumed per circuit breaker per year.

IEEE Std 500-1984 [B18] is a reliability data manual for use in the design of nuclear power generating stations. The equipment failure rates therein cover such equipment as annunciator modules, batteries and chargers, blowers, circuit breakers, switches, relays, motors and generators, heaters, transformers, valve operators and actuators, instruments, controls, sensors, cables, raceways, cable joints, and terminations. No information is included on equipment outage duration times.

The Institute of Nuclear Power Operations (INPO) organization operates the Nuclear Plant Reliability Data System (NPRDS), which collects failure data on electrical components in the safety systems of nuclear power plants. Outage duration time data is collected on each failure. The NPRDS database contains more details than IEEE Std 500-1984, but INPO has followed a policy of not publishing its data.

Very extensive reliability data have been collected for electrical and mechanical eqnipment used on offshore platforms in the North Sea and the Adriatic Sea (see OREDA-92 [B31]). This includes generators, transformers, inverters, rectifiers, circuit breakers, protection equipment, batteries, battery chargers, valves, pumps, heat exchangers, compressors, gas turbines, sensors, cranes, etc. Data have been published on failure rates, number of demands, failures per demand, repair time, and hours of repair labor. Ten oil companies have participated in this data collection over a period of nine years.

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.

[B1] Adler, R. B., et al., "An IEEE survey of U.S. and Canadian overhead transmission outages at 230 kV and above," *IEEE Transactions on Power Delivery*, vol. 9, no. 1, pp. 21-39, January 1994, http://dx.doi.org/10.1109/61.277677.[1,2]

[B2] Albrecht, P. F., et al., "Assessment of the reliability of motors in utility applications," *IEEE Transactions on Energy Conversion*, vol. EC-2, no. 9, pp. 396-406, September 1987, http://dx.doi.org/10.1109/TEC.1987.4765865.

[B3] Albrecht, P. F., et al., "Assessment of the reliability of motors in utility application—updated," *IEEE Transactions on Energy Conversion*, vol. EC-1, no. 3, pp. 39-46, March 1986, http://dx.doi.org/10.1109/TEC.1986.4765668.

[B4] Aquilino, J. W., "Report of transformer reliability survey—industrial plants and commercial buildings," *IEEE Transactions on Industry Applications*, vol. IA-19, no. 5, pp. 858-866, September/October 1983, http://dx.doi.org/10.1109/TIA.1983.4504299.

[B5] Averill, E. L., "Fast transfer test on power station auxiliaries," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-96, no. 3, pp. 1004-1009, May/June 1977, http://dx.doi.org/10.1109/T-PAS.1977.32415.

[B6] Dickinson, W. H., "Report of reliability of electrical equipment in industrial plants, part II: Application and industry," *Transactions of the American Institute of Electrical Engineers*, vol. 81, no. 3, pp. 132-151, July 1962.

[B7] Ekstrom, T. E., "Reliability/availability guarantees of gas turbine and combined cycle generating units," *Proceedings of 1994 IEEE Industry Applications Society Annual Meeting*, Oct. 2-5, 1994, Denver, CO, pp. 2209-2225.

[B8] Heising, C. R., et al., "Summary of CIGRE 13-06 Working Group world wide reliability data and maintenance cost data on high voltage circuit breakers above 63 kV," *Proceedings of 1994 IEEE Industry Applications Society Annual Meeting*, Oct. 2-5, 1994, Denver, CO, pp. 2226-2234.

[B9] IEEE Committee Report, "Cost of electrical interruptions in commercial buildings," *IEEE-ICPS Technical Conference Record*, 75-CH0947-1-1A, Toronto, Canada, May 5-8, 1975, pp. 124-129.

[B10] IEEE Committee Report, "Reasons for conducting a new reliability survey on power, rectifier, and arc-furnace transformers," *IEEE-ICPS Technical Conference Record*, May 1979, pp. 70-75.

[B11] IEEE Committee Report. "Reliability of electric utility supplies to industrial plants," *IEEE-ICPS Technical Conference Record*, 75-CH0947-1-1A, Toronto, Canada, May 5-8, 1979, pp. 70-75.

[B12] IEEE Committee Report, "Report of generator reliability survey of industrial plants and commercial buildings," *IEEE-ICPS Technical Conference Record*, CH1543-8-1A, May 1980, pp. 40-44.

[1] The IEEE standards or products referred to in Annex A are trademarks owned by The Institute of Electrical and Electronics Engineers, Incorporated.
[2] IEEE publications are available from The Institute of Electrical and Electronics Engineer, (http://standards.ieee.org/).

[B13] IEEE Committee Report, "Report on reliability survey of industrial plants, Parts 1-6," *IEEE Transactions on Industry Applications*, Mar./Apr. 1974, pp. 213-252; Jul./Aug. 1974, pp. 456-476; Sep./Oct. 1974, p. 681.

[B14] IEEE Std 141™, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants (*IEEE Red Book*™).

[B15] IEEE Std 242™, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (*IEEE Buff Book*™).

[B16] IEEE Std 315™, IEEE Standard Graphic Symbols for Electrical and Electronics Diagrams.

[B17] IEEE Std 493™, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (*IEEE Gold Book*™).

[B18] IEEE Std 500™-1984 (Reaff 1991), IEEE Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component, and Mechanical Equipment Reliability Data for Nuclear-Power Generating Stations.

[B19] IEEE Std 841™-2001, IEEE Standard for the Petroleum and Chemical Industry—Severe Duty Totally Enclosed Fan-Cooled (TEFC) Squirrel Cage Induction Motors—Up to and Including 370 kw (500 hp).

[B20] IEEE Std 1366™, IEEE Guide for Electric Power Distribution Reliability Indices.

[B21] IEEE Std 3006.3™-2017, IEEE Recommended Practice for Determining the Impact of Preventative Maintenance on the Reliability of Industrial and Commercial Power Systems.

[B22] IEEE Std 3006.5™, IEEE Recommended Practice for Use of Probability Methods for Conducting Reliability Analysis of Industrial and Commercial Power Systems.

[B23] IEEE Std 3006.9™-2013, IEEE Recommended Practice for Collecting Data for Use in Reliability, Availability, and Maintainability Assessments of Industrial and Commercial Power Systems.

[B24] IEEE Std 3007.1™, Recommended Practice for the Operation and Management of Industrial and Commercial Power Systems.

[B25] IEEE Std 3007.2™, Recommended Practice for the Maintenance of Industrial and Commercial Power Systems.

[B26] McWilliams, D. W., A. D. Patton, and C. R. Heising, "Reliability of electrical equipment in industrial plants—Comparison of results from 1959 survey and 1971 survey," *IEEE-ICPS Technical Conference Record*, 74CH0855-71A, Denver, CO, Jun. 2-6, 1974, pp. 105-112.

[B27] NSWC 11, "The Handbook of Reliability Prediction Procedures for Mechanical Equipment," published by the Naval Surface Warfare Center (Carderock Division), May 2011.

[B28] O'Donnell, P., "Report of large motor reliability survey of industrial plants and commercial buildings," *IEEE Transactions on Industry Applications*, Parts 1 and 2, Jul./Aug. 1985, pp. 853-872; Part 3, Jan./Feb. 1987, pp. 153-158.

[B29] O'Donnell, P., "Report of switchgear bus reliability survey of industrial plants," *IEEE Transactions on Industry Applications*, vol. IA-15, no. 2, pp. 141-147, March/April 1979, http://dx.doi.org/10.1109/TIA.1979.4503629.

[B30] O'Donnell, P., "Survey of lower voltage breakers as found during maintenance," *IEEE Industrial and Commercial Power Systems Technical Conference*, 6-9 May, 1996, New Orleans, LA.

[B31] OREDA-92, *Offshore Reliability Data Handbook*, 2nd ed. Norway: OREDA, 1992.

[B32] Patton, A. D., "Determination and analysis of data for reliability studies," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-87, no. 1, pp. 84-100, January 1968, http://dx.doi.org/10.1109/TPAS.1968.292260.

[B33] "Report on Equipment Availability for 10 Year Period 1965-74," EEI Publication no. 75-50 (Prime Mover Generation Equipment).[3]

[B34] "Report on Excitation System Troubles—1975," EEI Publication no. 76-78, Dec. 1976. (Later data have also been published.)

[B35] "Report on Generator Troubles—1975, "EEI Publication no. 76082, Dec. 1976. (Later data have also been published.)

[B36] "Report on Metalclad Switchgear Troubles—1975," EEI Publication no. 76-82, Dec. 1976. (Later data have also been published.)

[B37] "Report on Motor Troubles—1975," EEI Publication no. 76-79, Dec. 1976. (Later data have also been published.)

[B38] "Report on Power Transformer Troubles—1975," EEI Publication no. 76-80, Dec. 1976. (Later data have also been published.)

[B39] "Report on Power Circuit Troubles—1975," EEI Publication no. 76-81, Dec. 1976. (Later data have also been published.)

[B40] "Summary of Replies to the 1982 Technical Questionnaire on Rotating Machinery (Motors 1000 hp and Up)," unpublished report at Doble Conference, Apr. 1982, Boston, MA.

[3] These data are now collected and published by the North American Electric Reliability Council (NERC). NERC publications are available from the North American Electric Reliability Corporation (http://www.nerc.com/).

IEEE
standards.ieee.org
Phone: +1 732 981 0060 Fax: +1 732 562 1571

EPRI

A Review of the Reliability of Electric Distribution System Components: EPRI White Paper

Technical Report

A Review of the Reliability of Electric Distribution System Components: EPRI White Paper

1001873

Technical Progress, December 2001

EPRI Project Manager
S. Chapel

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

VMN Group LLC
Gregory L. Hamm

ORDERING INFORMATION

REQUESTS FOR COPIES OF THIS REPORT SHOULD BE DIRECTED TO EPRI CUSTOMER FULFILLMENT, 1355 WILLOW WAY, SUITE 278, CONCORD, CA 94520, (800) 313-3774, PRESS 2.

CITATIONS

This report was prepared by

VMN Group LLC
26789 Shady Oaks Court
Los Altos Hills, CA 94022

Principal Investigators
C. Feinstein
P. Morris

Gregory L. Hamm
933 Taylor Avenue
Alameda, CA 94501

Principal Investigator
G. Hamm

This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

A Review of the Reliability of Electric Distribution System Components: EPRI White Paper, EPRI, Palo Alto, CA: 2001. 1001873.

REPORT SUMMARY

This report discusses available literature, data, and models related to the reliability of electric power distribution system components and discusses the influence of environmental factors and testing results on component reliability. It also critiques the value of this information for value of service studies.

Background

EPRI has been developing methods for distribution planning since 1992. At that time, research directed at the concept of distributed resources begun by EPRI, Pacific Gas & Electric (PG&E), and the National Renewable Energy Laboratory (NREL) led to further consideration of distribution planning in general. More recently, this analysis has raised the issue of an aging distribution infrastructure and how to optimize maintenance and replacement of aging systems.

Objectives

To document what is known about reliability of individual distribution system components as they age and to determine whether sufficient information exists to perform the required reliability analysis of aging distribution systems.

Approach

A detailed literature survey, described in the report, created a Reliability Data Library, a tool intended to support further development of models and methodology. The Reliability Data Library can be used by utilities to locate component reliability data and information on other topics related to the reliability of aging components.

Results

The literature review found extensive data available on the reliability of individual components. With cautious use, this data can provide the basis for system reliability analyses. However, reliability is greatly influenced by maintenance and environmental factors that are unique to individual utilities. This report's key finding is that it is extremely important that individual utilities track their individual component reliability so that over time they can understand the unique reliabilities of their installed components. There is no single, generally available dataset that distribution planners can use to answer all questions associated with reliability-based planning.

EPRI Perspective

As distribution systems age, planners increasingly face repair, upgrade, and replacement decisions. The problem of aging assets has become more important because of the increasing emphasis on reliability, customer service, and cost reduction. The EPRI Distribution Aging Asset project is developing methodology, data, and software tools to help companies determine "maximum value," repair/replace strategies for existing distribution assets; generate business cases for investment and O&M decisions; evaluate risks; and, focus manpower on high-value solutions.

The project began in 2000 and a Research Status Report was published. That report (EPRI report 1000422) describes research done to identify and develop analytical methods for making decisions about aging assets in electric distribution systems.

In 2001, the EPRI project team designed and implemented repair/replace software specifically tailored for electric distribution equipment. Extensive equipment failure research also was initiated. While that research will continue through mid-2003, two databases have been compiled—one contains equipment failure rate information and the other lists and summarizes equipment failure literature. Both of these databases are available on the website www.vmngroup.com and will be updated as new information becomes available. This research Status Report summarizes the 2001 Equipment Failure research.

Keywords

Reliability
Reliability of distribution systems
Failure rates
Hazard functions

ABSTRACT

This report describes data available on the reliability of electric power distribution system components. The document describes the data on failure rates and the data available on the change of failure rates with aging. It also discusses the qualitative impacts of maintenance, environment, and monitoring on the reliability of aging assets. The report is based on an extensive literature survey that investigated papers, reports, and books. The literature review found extensive data available on the reliability of individual components. With cautious use, this data can provide the basis for system reliability analyses. However, reliability is greatly influenced by maintenance and environmental factors that are unique to individual utilities. This report's key finding is that it is extremely important that individual utilities track their individual component reliability so that over time they can understand the unique reliabilities of their installed components. There is no single, generally available dataset that distribution planners can use to answer questions associated with reliability-based planning.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

The key objective of the study was to determine whether sufficient published information exists to perform quantitative reliability analyses of aging distribution systems.

The study had a number of secondary objectives, including:

- To critique the current state of information on aging assets,
- To create a data base of information on the reliability of individual distribution system components as they age,
- To gather information on how environmental and maintenance differences can affect reliability,
- To gather information on how monitoring and testing can help in the determination of reliability,
- To identify how researchers have modeled the impact of aging on reliability, and
- To identify how information on individual component reliability can be used to support optimization of maintenance, monitoring, and replacement decisions.

This report presents the results of our study. It focuses on the available data related to the reliability of electric power distribution system components and the influence of environmental factors and testing results on component reliability.

What we looked at

The central purpose of our work was to determine and document the data available on the reliability of aging distribution system equipment. One author [Willis, 1997, p. 9] notes that transmission lines run voltages from 69kV to 1,100 kV and that distribution feeders run voltages of 2.2 kV to 34.5 kV. In general, we will define equipment running at 34.5 kV and below as distribution equipment and this will be the focus of our work. We do make exceptions for some distribution substation equipment that operate at voltages higher than 34.5 kV, in particular buswork, circuit breakers, and transformers.

Our primary approach to this task was via the published literature. We reviewed 191 publications, mostly journal articles and proceedings. The search for articles was conducted based on the following resources:

- The reference lists from earlier EPRI studies of distribution system reliability planning including Distribution System Reliability Handbook [Kostyal, 1982], Customer Needs for

Electric Power Reliability and Power Quality [Chapel, 2000(1)], Managing Aging Distribution System Assets [Chapel, 2000(2)], and Reliability of Electric Utility Distribution Systems [Chapel, 2000(3)];

- The reference list from a Canadian Electrical Association publication Guide to Value-Based Distribution Reliability Planning, Volumes I and II [Godfrey, 1996];
- An electronic search of publications dealing with electric power based on the key words: electric power and/or failure, common mode failure, loss-of-life and/or repair, replacement and/or distribution system, distribution system components, transformer, substation transformer, pole transformer, reclosers, switchgear, cable, conductor, underground cable, underground conductor, overhead cable, overhead conductor, overhead wire, capacitors, poles;
- A search of IEEE publications with a similar key word list;
- A search of the University of California library system on-line catalog; and
- References given by each paper reviewed.

What we produced

The study has produced three major products.

The largest and most significant product of the study is the database of articles. This database currently resides in Microsoft Excel and a copy also appears in Appendix A. As noted above, there are currently 191 entries. The database contains a complete reference for each article. It can be sorted based on reference characteristics such as Title, Publication Title (for publications from Journals and Proceedings), year of publication, and author. Publications are also classified by the component they deal with, a primary topic and a secondary topic and can be sorted by these classifications. The component classes are: System, Multiple, Generators, Cables, Capacitors, Poles, Switches, Transformers, Other, and Non-specific. Topic classes are: Financial Models, Technical Models, Causes of Failures or Wear, Discussions of Monitoring and Testing, Discussions of Design, Discussions of Maintenance and Replacement, Failure Rate Data, Failure Rate Equations, and Other.

The final fields in the database are the Summary and Notes fields. The Summary field provides an abstract or summary of what the publication covers. If the author has provided an abstract, we generally use that as a base and expand the description to cover aspects of the paper of particular interest to this study. The notes field is used for comments on the publication particular relevant to this study and most importantly to describe any data in the publication on reliability or failure rates. When available, we describe the origin of the data, the sample size, and the period over which it was collected. For each table of interest we describe the column and row headers and the entries in some detail. For each graph of interest, we describe the axes and the plotted data. We also include comments on the accuracy of the data, both those of the author and our own based on our review of the paper.

The second product of this effort is a summary database of the reliability data contained in the reviewed papers. This database is again in Microsoft Excel. The database is also found in

Appendix B. The rows of the database refer to individual distribution system components. These are grouped under: Buswork; Cables and Conductors; Cable and Conductor Connections; Capacitors; Poles; Switches, Circuit Breakers, and Fuses; Transformers and Other. The columns are divided into three sections.

The first section is simple failure rate data for the components. Units are failures/unit-year or failures/mile/year (for cable and conductor). Each column represents data from a single publication.

The second section contains data related to the impact of aging on reliability. Aging data include hazard rates. The hazard rate is the probability of a component failing over a short interval of time given that it has survived to a particular age. For example a 10-year old, pole-mounted transformer might have a hazard rate of 3.00E-03/year. Aging data about the components are summarized in five entries per source. These are: the source, hazard rate at 10 years, hazard rate at 20 years, hazard rate at 30 years and notes on the method of obtaining or calculating the hazard rates.

The third section contains data on the typical time to callout, isolate, and repair or replace components. Units are hours. Each column represents data from a single publication.

2 CLASSIFICATION OF PAPERS

As noted above, the database classifies the papers according to ten topics. For discussion it may be useful to distinguish four larger groups: publications dealing with failure causes, monitoring and maintenance; publications dealing with financial and technical modeling; publications dealing with data and failure equations; publications dealing with other topics.

About 25% of the publications deal with causes (7%), monitoring (12%), and maintenance (6%). We group these because they all deal with the hardware or the mechanics of failure. Many of these papers focus on a specific component. Transformers are by far the most thoroughly discussed.

Causes of failure or more rapid aging are:

- environmental - such as moisture, wind, ice, temperatures;
- use - such as loading, frequency, hours and
- maintenance - such as painting, tree clearing and fluid changes.

Publications in this area provide the reader with a qualitative understanding of how different circumstances will affect aging. In some cases, fairly specific recommendations are made on actions to reduce the impact of these causes of failure.

Many of the monitoring and maintenance papers provide substantial technical detail about monitoring or maintenance processes; and, many make specific recommendations on monitoring and maintenance regimens. However, with one exception [ABB Power T&D Company, 2001], none provide formulas that quantitatively relate monitoring or maintenance to failure rates or reliability.

45% of the papers discuss financial (19%) and technical (26%) modeling. These two approaches are distinguished by the objective function of the model. If the objective function is net benefit, usually measured in dollars, they are classified as financial. If the model is solely predictive of reliability, the publication is classified as technical. Some of these papers are purely theoretical. Many more present case studies or describe computer aids for financial or technical analysis. These papers are part of the literature that was the focus of earlier EPRI studies and papers, for example, *Distribution System Reliability Handbook* [Kostyal, 1982], *Managing Aging Distribution System Assets* Chapel, 2000(2)] and *Reliability of Electric Utility Distribution Systems* [Chapel, 2000(3)]. They expand upon the understanding of the state-of-the-art presented in those reports. The reports often provide failure rate data in the context of the case studies or examples presented.

A number of financial modeling papers specifically address value-based reliability planning or reliability centered maintenance.

23% of the papers are focused on reliability data or equations describing reliability. These are discussed in more detail in the next section.

The final 7% of the papers cover design (5 papers) and other topics (8 papers).

In addition to the reference database, we have gathered a Reliability Data Library, which is located at EPRI. This contains hardcopies of all the references described in the database except for a few books and reports that are held in the main EPRI library. Most of the hardcopy materials are copyright protected and have limitations on reproduction.

3
DATA

Overview

Figure 3-1: Typical Bathtub Curve of Failure Rates illustrates the failure pattern typically assumed for electric components. Early in their life, equipment experiences a high rate of failures often due to manufacturing or installation problems. There is then a long middle-life period of low and relatively stable failures due to random causes. Then equipment begins to wear out and aging causes the failure rate to accelerate. Depending on many factors discussed below, this failure pattern will differ for the same or similar components. Some will experience higher and lower than normal failure rates. We assume that when simple failure rates, stated as failures/year or failures/mile/year, are given, the failure rates refer to the failure rate during the long period of little change or a lifetime average that would be somewhat higher but generally close to the rate during a component's middle-life.

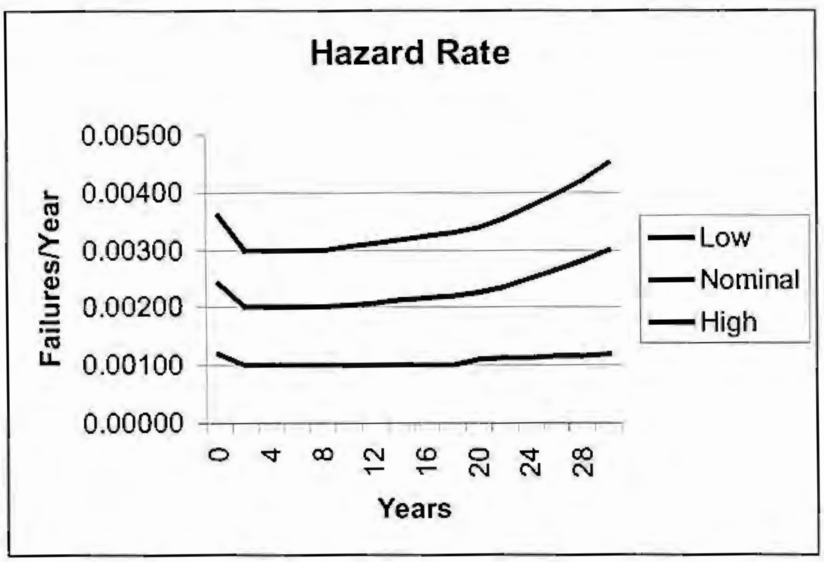


Figure 3-1
Typical Bathtub Curve of Failure Rates

The overwhelming bulk of the data are simple failure rates. Nineteen references present failure rate data that were included in our summary equipment database. Most of these present data on a number of components. Thirteen references provide data on the affects of aging on reliability that were included in our summary equipment database. Most of these deal with only one or two related components, for example, two types of underground cable.

A simple failure rate can be found for almost any (perhaps all) components in the distribution system. Failure rates for 82 components are provided. The references provide data for a still more detailed breakdown of components. Except for Buswork, at least one aging reference is available for all the major component areas: Buswork; Cables and Conductors; Cable and Conductor Connections; Capacitors; Poles; Switches, Circuit Breakers, and Fuses; Transformers; and Other. In this sense we have quite good coverage. Generally, if data is the focus of the publication, the sample size and dates of data collection are provided, but little else. Data from sources where modeling is the primary topic and data the secondary topic are generally not well documented. Those papers developing failure functions over time use a variety of methods and usually there are significant questions about their analysis methods.

Table 3-1: Summary of Failure Data presents data for seventeen components. Data is presented in much more detail in Appendix B. The low and high values in the table illustrate the range of simple failure rates for each component that we found in the literature. The 10 to 30 year multiple is an indication of the increase in failures with aging. The 10 to 30 year multiple is the failure rate for equipment that is 30 years old divided by the failure rate for equipment that is 10 years old.

This table starkly illustrates the very wide range of failure rates found in the literature. The high failure rate is frequently one, two, or three orders of magnitude greater than the low failure rate. An initial conclusion might be that data with this range of variation are of no value. We do not believe that this is an appropriate conclusion. We believe that it does indicate that each utility is unique and may experience very different failure rates. The data can be useful, but each utility must examine the underlying sources and determine which data are most likely to be appropriate for the utility's unique situation. The variance in the data and the apparent uniqueness of failure rates also suggest that each utility should initiate its own data collection program.

Table 3-1
Summary of Failure Data

	Failures/year		
Component	**Low**	**High**	**10 to 30yr Multiple**
Busbars	1.50E-03	1.10E-02	NA
Overhead conductor (per mile)	1.22E-02	1.80E+00	1.3
Underground cable (per mile)	7.35E-04	4.50E-01	2.7
Underground splices	1.00E-04	2.10E-03	6.5
Elbows	1.90E-04	1.50E-03	2.2
Capacitor Banks	8.50E-03	1.74E-01	21.4
Wooden Poles (one value)	3.34E-05	3.34E-05	38.3
Switches	1.50E-04	1.60E-01	3.1
Circuit breakers	2.00E-04	3.60E-02	1.2
Recloser	1.44E-03	1.50E-02	1.3
Fuses	8.70E-04	4.50E-03	1.0
Substation Transformers	1.50E-02	7.00E-02	NA
Pole-mounted Transformers	1.60E-05	4.40E-03	1.40
Pad-mounted Transformers	2.00E-03	4.50E-02	8.7
Submersible Transformers	1.38E-03	3.08E-03	1.5
Lightning Arrester	2.00E-04	1.32E-03	2.9
Voltage Regulator	2.88E-02	3.63E-02	NA

Table 3-2: Summary of Data Quality presents our qualitative judgments about the quality of the data for various components. Average quality means that there are multiple sources, at least one source is well documented, and that component definitions are appropriately detailed and clear. Below average indicates that there are few sources, data analysis or collection processes may be questionable, and/or definitions are unclear. Above average indicates multiple, well documented sources for the data.

Table 3-2
Summary of Data Quality

Component	Quality	Comments
Busbars	Below	Definitions uncertain
Overhead	Average	Several sources, some voltage differentiation
Underground	Above	Many sources, wide range of types of cable
Underground splices	Below	Little differentiation of types in data
Elbows	Average	Several sources, relatively high consistency
Capacitor Banks	Below	Few and uncertain sources
Wooden Poles	Below	Few sources
Switches	Below	Definitions uncertain, little differentiation of types in data
Circuit breakers	Average	Ok sources, wide range of types
Recloser	Average	Several sources, relatively high consistency
Fuses	Average	Assumed this is a simple component
Substation Trans	Below	Few sources, no aging data
Pole-mounted Trans	Above	Several reliable sources
Pad-mounted Trans	Above	Several reliable sources
Submersible Trans	Average	Average number of sources, some range of types
Lightning Arrester	Average	Assumed this is a simple component
Voltage Regulator	Below	One source

Problems

Problems with the data will be discussed under three headings: data gathering and reporting, component variability and the integration of monitoring data.

Problems are caused by limited information on the sources and methods of data collection and issues of definition. As noted above, many of the publications do not report fully the source of the data or details of the sample and data collection procedure. Equipment descriptions generally omit design information (for example, type and thickness of cable insulation) and size (voltage or other size indicators). There is almost never any indication of the operating conditions or the level of maintenance. These omissions leave no guidance as to the weight that should be put on the data or its appropriate application.

Issues related to definition also abound. These include:

- Names for equipment. As an example data is provided for Switches, Substation disconnect switches, Overhead switches, Underground pad mount switches, Automatic transfer switches, Manual transfer switches, Oil filled switches, Switches >5kV and Static switches. The extent of overlap in these definitions and the similarities in the switches is unclear.
- What is a failure? Several sources distinguish between minor and major failures. Are only wear or age related failures reported? Are failures due to extreme weather conditions or accidents included? How are failures on parallel lines or closely associated pieces of equipment treated? Usually, sources do not answer these questions.
- What is included in time to repair? Does this include the time to locate, get crews to the problem, isolate, and repair or some subset of these activities? Again, sources usually do not answer these questions.
- Modeling terms such as hazard rate, failure function, extreme value distribution, Winfrey curve, and a number of others are often either poorly defined or, in some cases, obviously misused.

It should be noted that IEEE has recognized these definition problems for some time and has published several papers providing guidelines for definitions and the organization of databases of failure information. [IEEE, 1968], [Guertin, 1976] Utilities that follow these guidelines should have internally consistent data. However, the guidelines allow a good bit of flexibility and, even if utilities follow these recommendations, problems in combining information from different utilities are likely.

The discussions of data gathering, failure causes and maintenance make it very clear that identical equipment in different environments are likely to have very different failure rates and aging patterns. We might divide these factors into manufacture, environmental, use, and maintenance.

One manufacturing issue is design. We use cable as an example because it is perhaps the simplest piece of equipment. Cable obviously differs in size, but it also differs in the insulating material and its thickness. It differs in its protection; it can be direct buried, in jackets, in duct, or in conduit. It differs in the method of installation; it can be ploughed, buried in a trench, or placed in other manners. Damage during installation can cause different reliabilities. Cable differs in the depth of burial. Several studies show that even if all the design and installation specifications are the same, reliability can differ with manufacturer.

The reliability of outdoor equipment will depend significantly on weather. Temperature, humidity, wind, lightning, snow and ice are all significant. Location will affect risks from trees, animals, accidents and vandalism. Indoor equipment will be somewhat less affected, but temperature, moisture, and ventilation are still environmental issues.

The use of equipment also has an impact on its failure rate and aging. Probably the most obvious item is the impact of extreme loads on transformers, switches, and many other components. However, there are other obvious and less obvious factors. For equipment loaded intermittently, the hours of operation and the number of cycles are significant factors. One less obvious condition is the existence of harmonics and the problems they create. One paper noted that the speed of a switch can cause momentary overloads in the equipment it controls and thus contribute to the controlled equipment's reliability.

Maintenance is a final category that can significantly impact reliability. Almost all outdoor equipment requires some level of maintenance such as painting or other weather proofing. Lines require tree trimming and the removal of other hazards. Many more complex pieces of equipment require regular cleaning, fluid renewal, lubrication or other maintenance. Lack of such maintenance can significantly change reliability.

The final problem that we want to note is how to integrate monitoring into our repair, replace and maintain decisions. Many non-destructive, destructive, in situ and laboratory tests are available for components and are actively used by utilities. However, we have found very little information incorporating monitoring and testing results quantitatively into reliability estimates. This seems to be an area where rules of thumb and professional judgment rule.

By component

Buswork

While definitions are a problem throughout, they were an especial problem with respect to buswork. In a typical distribution substation design, on the low voltage side of the power transformer, there is metal-clad switchgear. This includes a drawout circuit breaker, feeder circuit breakers, busses, and various connections. It is unclear which specific components are included under terms found in the literature such as: bus, buswork, busbar, switchgear bus, and switcbgear excluding circuit breakers. In this section, we assume these terms refer to similar components.

Data

Subcategories for buswork include: busbar; 132 kV busbars; switchgear bus, bare; switchgear bus, insulated; and bus duct, all types. For most of these items only one or two references were available for failure rates. For "switchgear bus, bare" four sources were available; however, failure rates ranged from 4.4E-04 units/year to 4.0E-02 units/year - nearly, a hundred fold difference. This wide range may be due to definitional problems or extremely varied uses for this category of equipment.

No data were found for the impact of aging.

Cable/Conductor

Data

Data for cables and conductors are listed under two major subheadings, overhead and underground, and under fifteen different minor subheadings. These are, for overhead conductors >15kV and <15kV and, for underground cables, approximately 600V solid, 15kV solid, 25kV solid, direct buried polyethylene (PE), direct buried HMWPE unjacketed, direct buried XLPE unjacketed, direct buried TRXLPE-SF-PEEJ, in duct XLPE, in cov. duct XLPE, in C.E. Duct XLPE, in C.E. duct TRXLPE-SF-PEEJ, 15kV paper, 25kV paper. Data on simple failure rates come from twelve different sources, and data on aging come from six different sources. We suspect that some of these sources are redundant in the sense that they draw from the same database of failures. (For example, the same author publishes similar data in two different papers.) However, we can't confirm the independence or dependence of sources.

Where we have three or more sources for the same titled item, simple failure rates typically differ by an order of magnitude. Here are some examples:

Table 3-3
Cable Failure Rates

Item	High	Low
Distribution	1.80E-00	1.22E-02
Aerial,<15kV	2.49E-01	1.22E-02
Underground	4.00E-01	1.17E-03
XLPE	4.02E-02	2.00E-03

With respect to aging, several sources show very little deterioration of cable with age. More typically the references show a doubling of failure rate from 10 year old cable to 30 year old cable. The most extreme is an approximate tripling of failure rate from 10 year old to 30 year old cable.

Causes

Overhead conductors fail due to overloading by snow or ice, tree problems, high winds causing clashing and arcing, and fatigue from vibration. Aluminum conductor may also be weakened by corrosion. [Wareing, 1998, p. 2/4-2/5]

In most areas, trees or branches falling, blowing, or growing into lines are the single greatest cause of outages. "$2 billion is spent on vegetation management each year." [Willis, 2001(2), Section 7, p. 19] High winds and ice are often associated with tree problems.

In some areas, lightning may be the primary cause of overhead line failure. Lightning failures depend not only on the region and the level of thunderstorms, but the particular location of the line, such as an exposed hillside versus a valley, and the lightning protection from arrestors, insulators, use of overhead ground wires, level of grounding and soil moisture content.

Conductor is valuable and conductor theft can be a problem. [Wareing, 1998, p. 2/9]

Birds pose two problems: they bridge the conductors with their wings and with streaming excrement. [Willis, 2001(2), Section 7, p. 14]

Underground cable life is affected by voltage surges, through-faults, loading and environmental conditions such as temperature, moisture, and installation configuration.

Water treeing is a mode of ingress of water into solid cable insulation. It has been a significant problem. Recent tree-resistant insulations appear to be improving this problem. [Willis, 2001(2), Section 7. p. 5]

Dig-ins are the largest source of failure for underground cable. Apparently depth of burial has a significant impact on both dig-in failures and other failures. One source [Arceri, 1976, p. 37] shows that failure rates from all causes are reduced by 44% when burial depth is increased from 30 inches or less to 40-48 inches.

Tests

Visual inspections are commonly used for overhead lines. A visual inspection will identify loose components, improper grounding, missing notices, problem trees, and problem structures or activities

Tests for cable include: partial discharge testing, dielectric spectroscopy, degree of polymerization, and insulation hardness. [Willis, 2001(2), Section 7, p. 8] One source reports that a proprietary series of tests from Ultra Power Technologies, Inc. has proven extremely cost effective in identifying problem cable prior to failure. [Reder, 2000, p. 553]

Cable and Conductor Connections

Data

Data for splices is listed under 12 different headings. These are: pole top terminators, molded rubber; splices; 15kV solid splice; 25-kV solid splice; 15kV paper-solid splice; 25kV paper-solid splice; 25kV/15kV paper splice; elbows; loadbreak elbows/terminators; non-loadbreak elbows/terminators; 15-kV deadend cap. Data on simple failure rates come from ten different sources. Again, we suspect that some of these sources are redundant in the sense that they draw from the same database of failures.

There are three sources of data on aging.

Only one reference is available for pole top terminators. This shows a failure rate of 5.73E-05, a very low failure rate.

Underground splices have nine references. The failure rates for the general category splice range from 1.90E-04/year to 1.00E-03/year. However, a reference for the more specific category of 25kV solid-to-solid splices shows a high failure rate of 8.80E-01.

One source shows no deterioration of cable with age. Another source shows between a 2.5 and 3.0 multiple of the 10 year failure rate at 30 years.

Loadbreak elbows have a failure range from 2.63E-03 to 1.50E-03. Common references show consistently lower failure rates for non-loadbreak elbows. These range from 1.90E-04/year to 1.00E-03/year.

For underground splices, most references show failure rates rising by a factor of 3 to 3.5 from 10 years to 30 years of age. One reference shows the failure rate for loadbreak elbows rising by a factor of 4 from 10 years to 30 years of age. A second shows a rise over the same period of only about 75%. The single reference on aging in non-loadbreak elbows shows no deterioration with age.

Causes

Failures in overhead joints and accessories are often caused by improper design or installation. Stays can break due to fatigue or corrosion. [Wareing, 1998, p. 2/4] Wind can induce vibration which leads to fatigue. [Allison, 1995, p. 182]

Water has negative effects on both cable and cable joints. In particular in aluminum joints, water can react with the aluminum to create a gas, and the gas pressure can cause joints to fail.

Tests

Conductor corrosion can be detected by an eddy-current technique to detect the galvanic corrosion process in steel reinforced aluminum conductor. [Allison, 1995, p. 182]

Helicopter inspection of overhead lines can use a corona detection technique to identify fatigue fracture or wear in strands and fittings and an infra-red camera to detect joint deterioration. [Allison, 1995, p. 182]

Capacitor Banks

Data

There are five references for failure rates for capacitor banks. These range from 8.50E-03 up to 1.74E-01. The two references on aging in capacitor banks indicate that they age very significantly. One shows a five-fold and another shows a 35-fold increase in failures from 10 years to 30 years.

Causes

One study of capacitors indicated that the composite dielectric was the leading cause of failure. More fundamental problems are faulty seals, over voltage, and partial discharge. Oil switches create a particular problem. They produce a restrike after contacts have been opened, causing a switching overvoltage, which in turn causes a partial discharge, which in turn leads to degradation of the dielectric. [Faraq, 1999, p. 341-344]

Poles

Data

Only two sources were found for pole failure rates. The failure rates are very low. For wooden poles the given rates are 3.34E-05/year and 3.11E-04 at 10 years. For concrete poles, a 0.00E-00 is given at 10 years. At 30 years, the failure rate for wooden poles has risen significantly to 1.09E-03 and 2.04E-02, from the comparable references. For concrete poles at 30 years, the failure rate is more than 50 times lower than wood at 2.37E-05.

Causes

Steelwork faces rust problems, but steelwork is more generally replaced for re-conductoring with heavier conductor than due to failure [Wareing, 1998, p. 2/4].

Particularly in warm, moist environments rot is the main killer of wood poles. Drier climates cause pole checking which creates avenues for the entrance of wood destroyers. [Nelson, 1998, p. 3/3] Animals can also cause significant pole problems. Animals bridging phase wires can cause damage to pole tops. Wood peckers damage the structure of the poles. Burrowing can weaken soil support. Larger animals that use poles as rubbing posts can weaken poles. [Wareing, 1998, p. 2/9]

Tests

Visual inspection from the ground or from climbing/bucket trucks will look for loose components, improper grounding, out of plumb poles, missing notices, ineffective anti-climbing devices, ineffective stays and visible damage, such as from woodpeckers. [Nelson, 1998, p.3/4-3/5]

Other common tests for wood poles include: sounding, drilling or coring, and excavation. [Nelson, 1998, p. 3/5]

There are a number of more recently developed methods of decay detection.

- Sonic and ultrasonic devices send sound waves through the wood. Variations in speed indicate different wood densities; the speed is slower through less dense, weaker material. EPRI has developed a program that correlates results with the bending strength of poles.
- X-ray and NMR, nuclear magnetic resonance, devices also detect differences in densities. These technologies are more expensive than sonic devices but can create two- and three-dimensional mappings of pole densities.
- A decay detecting drill drills a very small whole with a flexible bit. It can detect differences in the hardness of the material being drilled through.
- Electrical resistance instruments operate on the principal that negative ions are released by wood when it is infected by decay.
- The *Polux* instrument has two electrodes that are driven into the wood. These electrodes measure density and moisture content. The density and moisture measurements have been correlated with compression strength as determined by destructive testing. The adequacy of pole strength is based upon the estimated compression strength.
- Mechanical deflection instruments apply a bending force in-situ and measure the deflection. [Nelson, 1998, p. 3/5-3/20]

Switches/Circuit Breakers/Fuses

Data

Data is available for eight headings under switches, eight headings under circuit breakers, reclosers, and three headings under fuses. These headings are: switches; substation disconnect switches; overhead switches; underground pad mount switches; automatic transfer; manual transfer; oil filled, >5kV; static; circuit breakers; < 600V; 11 kV; 63-100kV; 132 kV; circuit breaker 3 Phase, fixed; circuit breaker, drawout; circuit breaker, vacuum; recloser; fuses; overhead fuses; underground, fuses. For many of these headings, we have only one source. However, we have five sources for simple failure rates of substation disconnect switches, eight sources for overhead switches, and five sources for switches on underground systems. For the general category of circuit breakers, there are five sources. For reclosers, there are seven sources; and for fuses on overhead systems, there are eight sources. The table below lists lows and highs for these six components.

Table 3-4
Failure Rates of Switches, Circuit Breakers, Reclosers, and Fuses

	Failure Rate	
Component	**Low**	**High**
Substation Disconnect	1.50E-04	1.60E-01
Overhead	7.75E-04	1.40E-02
Underground	1.00E-03	1.00E-02
Circuit Breakers	3.00E-03	2.00E-02
Reclosers	1.44E-03	1.50E-02
Overhead Fuses	8.70E-04	4.5E-03

Where multiple sources are available, they suggest very different impacts of aging. One source shows no aging for switches from 10 to 30 years of age, another shows failures rising by a factor of five. Data for circuit breakers completely parallel that for switches, two sources show no impact of aging and a third shows failures rising by a factor of five. For reclosers and fuses, only one source is available for each. The recloser source shows a very low 25% increase in failures from 10 to 30 years. The fuses source shows no increase in failures over the same period.

Causes

Mechanical faults with the drive mechanism, contact erosion and leakage are the main problems experienced with circuit breakers. [Allison, 1995, p. 183]

Overloading and heat are the key underlying causes of switchgear failure. Heating problems can be exacerbated for outdoor equipment by solar radiation. Problem areas include:

- Contacts. Oxide film growth can lead to arcing at contacts. In air, this triggers insulation breakdown and flashover. In oil, this leads to gas generation and explosions.
- Compound insulation. Compound filled chambers leak with increasing operating temperatures, this can lead to busbar faults.
- PVC insulation. Overloads lead to cracking and ultimately to busbar faults. Overheating, particularly coupled with moisture, can reduce the insulation resistance of dielectric materials.
- Cable terminations. Expansion and contraction create severe mechanical forces that can lead to high resistance connections. Together with overloading this creates problems with insulation.
- Current transformers. Overloaded circuit breakers lead to overloads in associated current transformers. The temperature rating for the insulation on the secondary windings can be exceeded leading to shorted turns and protection failures. [Wareing, 1998, p.2/5]

A European study of circuit breakers of 63kV to over 700kV found that 43% of failures were in the operating mechanism and that 54% of failures could be attributed to design or manufacture. [Fletcher, 1995, p.28]

Corrosion is a major problem with switchgear used outdoors. If wind driven rain can enter joints and assemblies, corrosion problems are exacerbated. Visual inspection, cleaning, and painting are important maintenance items. [Pryor, 1987, p. 94] Bi-metallic corrosion has also been know to cause problems with contacts. [Pryor, 1987, p. 93]

Rodents and other small animals are a problem due to nesting in pad-mounted equipment.

Tests

Visual inspection can identify leakage in compound filled chambers. [Wareing, 1998, p. 2/6]. Visual inspection of gasketed joints for leakage and corrosion is also important.

Dielectric integrity is the only long-term factor associated with the deterioration of well maintained equipment. If switches are taken out of service, discharge testing can be performed in the laboratory. Bushings can be tested by capacitance, tan delta, and insulation resistance. Tests of insulating oil are also appropriate. [Pryor, 1987, p. 94-95]

Transformers

Data

The major classifications of transformers are substation, overhead or pole-mounted, pad-mounted, and submersible. In total, there are sixteen transformer headings under which we have data. These are: transformers, substation power transformers, 132/33kV transformer, overhead pole-mounted, 11kV/415V pole mounted, pad-mounted, 601v-15kV, 15kV, 25kV, 3 phase, 1 phase, forced air, submersible, vinyl, stainless, 1 phase below grade. For most of these categories, there are only one or two references. For pole-mounted and pad-mounted transformers there are eight sources for each.

Examining data from sources that cover several of the major transformer classifications, it suggests similar failure rates for pole-mounted, pad-mounted, and submersible transformers, and somewhat higher failure rates for substation power transformers. The table below shows the failure rate ranges for the major classes of transformers.

Table 3-5
Failure Rates for Transformers

	Failure Rates	
Component	**Low**	**High**
Substation	1.50E-02	7.00E-02
Pole-mounted	2.71E-04	5.00E-03
Pad-mounted	2.00E-03	4.73E-03
Submersible	1.38E-03	3.08E-03

There are two source for data on aging of pole-mounted transformers. The one we consider more reliable shows failures increasing by a factor of 50% from 10 years to 30 years. The other source shows a 15 fold increase in failures; however, this source also shows a 10 year failure rate 1/400th of that from the other source. There are four sources for aging data on pad-mounted transformers. There is very little correspondence among these sources. According to the source, alternative rates of failure between 10 years and 30 years increase by 1) 6%, 2) 50% to 73%, 3) 2 to 5 fold, and 4) 125 fold. The single source of aging data for submersible transformers shows a 50% increase in failures from year 10 to 30.

Causes

A CIGRE survey indicated that windings and terminals were the leading components causing failure of transformers in service (29% of total failures each). A US survey indicated that external corrosion, aging, and insulating oil together accounted for 37% of the causes of transformer failure. [Allan, 1995(1), p. 67]

Because of the thickness of the transformer tank wall and the ease of detection of surface corrosion, corrosion is generally not a significant problem. Pole-mounted transformers are somewhat subject to rusting tanks and erosion of arc gap electrodes. Transformers with cooling radiators have more significant corrosion problems because rusting within the radiators is harder to detect. Submersible transformers have had particular rust problems, but these are much lower with more modern vinyl and stainless steel types [Verheiden, 1976, p. 18, 20].

Several environmental factors can lead to transformer damage. Lightning can induce faults, particularly in pole mounted transformers. Geomagnetic disturbances are a potential cause of failure. At times of high sunspot activity, an interaction occurs between charged particles thrown off by the sun and the earth's magnetic field. This interaction causes electric currents in the upper atmosphere and mirror currents in the earth's crust. When these currents take a path through the power system, the currents can saturate transformer cores, actuate protection systems and disconnect transformers. The saturation can cause overheating and the disconnections can overload adjacent lines. [Allan, 1995(1), p. 70]

For oil filled transformers, the aging rate of the insulation is determined by temperature and the moisture and oxygen content of the oil. [Ferguson, 1987, p. 116] Overloading that results in heating and insulation deterioration is a problem for all transformers. The temperature for normal aging is 98°C. In the rage of 80°C to 140°C for every 6°C deviation above or below 98°C doubles or halves the rate of aging respectively. [Wareing, 1998, p. 2/5] Another reference states that a 10°C deviation causes doubling. [Willis, 2001(2), Section 7, p.3]

Ferroresonance is a high voltage oscillation that can occur with overhead line phase switching. These oscillations can cause mechanical damage to transformers. [Wareing, 1998, p. 2/7]

Submersible transformers suffer failures of the elbow-bushing combination due to mechanical stress [Verheiden, 1976, p. 20]

Load tap changers have a history of failure; however, new vacuum technology is much improved. [Willis, 2001(2), Section 7, p. 3]

Load losses are much lower in new transformers than in old. These losses are another factor in the economics of transformer replacement. [Ferguson, 1987, p. 116]

Tests

Transformers can be inspected visually for rust and leakage. [Wareing, 1998, p. 2/5]

Condition of the insulating oil in transformers is of great concern. Tests include: dielectric breakdown, neutralization number, interfacial tension, specific gravity, water content, color, visual examination, power factor, flashpoint, pour point, corrosive sulfur, viscosity, dissolved gas analysis [ABB Power T&D Company, 2001, Section 4, p. 11-12] and furfaldehyde [Ferguson, 1987, p. 115].

Condition of the transformer winding insulation sets the ultimate transformer life. These are difficult to inspect directly. Some of the oil tests are directed at identifying winding insulation problems, such as the gas in oil test and furfaldehyde test. Electrical tests that can help diagnose problems include: insulation resistance by DC Megger, loss angle, partial discharge and low voltage impulse tests. [Ferguson, 1987, p.114]].

Windings can shrink with age and become loose within the transformer. Most transformers provide adjustable clamping to handle this problem. As an alternative to internal inspection for looseness there are electrical tests that can aid in detection. Two methods are to measure the reactance of the windings and to use a low voltage impulse. [Ferguson, 1987, p. 115]

Transformers have been extensively studied. Little information was found on the quantitative adjustment of failure rates based on the history of use and testing for other components; however, for transformers significant information was available. ABB provides some of these adjustment equations [ABB Power T&D Company, 2001, Section 3, p. 6-17]. ABB also provides the following list of minimum required information for calculating transformer life:

- Top oil temperature rise over ambient at rated load
- Bottom oil temperature rise over ambient at rated load
- Average conductor temperature rise over ambient at rated load
- Load loss at rated load
- No-load (Core) loss
- Total loss at rated load
- Confirmation of oil flow design (directed or non-directed)
- Core and coil assembly weight
- Tank and fitting weight
- Volume of oil in the tank and cooling equipment (excluding LTC compartments, oil expansion tanks, etc.) [ABB Power T&D Company, 2001, Section 3, p. 11]

ABB lists the following items as allowing more accurate prediction of transformer life:

- Load loss at rated and tap extremes or all possible tap connection combinations.
- Winding resistance at tap extremes or all possible tap combinations
- Total stay and eddy loss as a percent of total load loss and estimated stray and eddy loss.
- Per-unit winding height to hot-spot location
- Load cycle in kVA on the actual combination of tap connections
- Use the measured or calculated load losses for that tap connection
- Correct the temperature rise data for the lower losses or different rated current.
- Determine if the hottest-spot winding gradient changes with changes in the tap connections. [ABB Power T&D Company, 2001, Section 3, p. 11]

Observation and testing is also useful for ancillary transformer equipment such as bushings and load tap changers. Bushings should be checked for the state of their insulation and discharge characteristics. Oil filled bushings can be tested for gas in oil. Similarly, oil samples from the selector compartment of tap changers can be checked for gas in oil. [Ferguson, 1987, p. 115] Tap-changers are also subject to mechanical failure. Acoustic and optical sensors can monitor for tap-changer problems. [Allison, 1995, p. 183]

Others

Data

Many different types of components are included under the other category. These include: arrester, lightning, battery, inverters, all types, meter, electric, rectifiers, all types, secondary connectors, UPS, voltage regulator, static. Many of these items are used much more in industrial distribution systems than in utility distribution systems. Lightning arrestors and voltage regulators are perhaps the most important for utilities. Simple failure rates for lightning arrestors vary from 2.00E-04 to 1.32E-03 across four sources. Voltage regulators have five sources but we suspect several are redundant (same data source quoted by different papers). The simple failure rates for voltage regulators vary from 2.88E-02 to 3.63E-02.

There is one source of aging data for lightning arrestors. This shows the failure rate going up by a factor of about three from 10 years to 30 years.

Causes

Arrestors can deteriorate by leakage through end seals or gradual decay from use. Ferroresonance can cause ungapped metal oxide arrestors to fail due to long-term overloading.

4 CONCLUSIONS

While there is a great deal of information published about component failure rates, the failure rate information is inconsistent and there is limited data about the effects of aging. An examination of available information emphasizes the difficulty in interpreting published information and the wide range of failure rates that an individual utility might experience.

Three factors complicate the use of published data: data gathering and reporting, component variability, and the integration of monitoring data.

- Published data often is not accompanied by sufficient documentation to determine its accuracy or applicability to a particular utility and component. Terminology describing both components and failures is varied creating an additional communication problem.
- The failure rates of components can vary greatly with manufacturer and utility specific characteristics. These characteristics include design and manufacturing specifics, installation procedures, equipment operating environment, manner of equipment use, and maintenance procedures.
- Monitoring and testing can provide information on the condition of components, but interpretation of results is often qualitative. Seldom are quantitative relationships available between test results and failure rates.

Some of these problems would be alleviated by a larger collection of data gathered on many components in a consistent manner. We have not found a published source of such data in our search. There is a possibility that such data exists but has not been published. We have initiated contacts with several organizations that might hold such data. These organizations include: Edison Electric Institute (EEI); North American Electric Reliability Council (NERC); U.S. Army Corp of Engineers, Special Missions Office, Power Reliability Enhancement Program; Canadian Electricity Association (CEA); Electricity Association (EA, of England and Wales); International Council on Large Electric Systems (CIGRE); and ABB (global power and automation technology). As of publication of this report, these organizations have not responded, but we hope to establish communication with them in the future.

The results of this study should be of immediate use to utilities. The reference database should help planners locate information on: failure rates, causes of failures, and maintenance and monitoring procedures. The reference database also provides a guide to many case studies of failure rate analyses and approaches to system planning and design. Finally, the equipment database provides a quick source of failure rate data (this data should be used with an understanding of its limitations).

We believe that further research and data gathering can add significant value. We suggest that the following activities be undertaken:

- The reference and equipment summary databases should be maintained and expanded. If the databases become outdated, their current value will be lost. Given the foundation established by this report, maintenance and expansion should be significantly less costly than the initial development.
- We believe that individual utilities will use a combination of utility specific internal databases, published data, and expert judgment to develop databases that can be used for their system analyses. The specifics of what kind of database a utility needs and how these three sources can be used to establish such a database is unclear. Three to five published case studies could clarify this process and provide real and widely applicable examples of how a utility can quickly establish a useful database.
- Best practices for internal tracking of failure rates have not been established and widely disseminated. The data gathering process should be coordinated with the development of methods for analyzing aging systems currently ongoing at EPRI. This will assure the data and analytic procedures fit together. A guidebook on internal tracking of failure rates would document the best practices.

A
REFERENCES

ABB Power T&D Company.

ABB Power T&D Company, 2001

ABB Power T&D Company

"Equipment loading, lifetime replacement, and optimality workshop," 2001, February 23, EUCI, Denver, Colorado

A series of presentations at a workshop hosted by ABB Power T&D Co. Topics covered include conditions assessment, aging equipment and its impacts, aging power T&D infrastructures, transformer loading and loss of life determination, and planning for failures.

General overview of monitoring and testing. Lists diagnostic tests and provides a graph showing the relationship between Furanes and Degree of Polyermization of cellulose.

General overview of how failure rates are quantified, how maintenance and replacement affect overall failure rates, and how the population of units in service ages. Provides some failure rate data in the form of small graphs.

The section on aging power T&D infrastructures begins with a discussion of what aging or old equipment means and moves on to a very general discussion of managing aging equipment.

The transformer section provides a great deal of detail on how transformers age. It states that the normal life expectancy at 30 degree C and conductor hottest-spot temperature of 110 degree C is 20.55 years.

It includes discussions of the affects of aging, temperature, and loads. It provides equations to calculate insulation life in years based on hottest-spot temperature, ambient temperature, and loading. It, also, provides tables indicating impacts of ambient temperature and loading on life. It lists the following as necessary information to calculate loss of life: top oil temperature rise over ambient at rated load, bottom oil temperature rise over ambient at rated load, average conductor temperature rise over ambient at rated load, load loss at rated load, no-load (core) loss, total loss at rated load, confirmation of oil flow design (directed or non-directed), core and coil assembly weight, tank and fitting weight, volume of oil in the tank and cooling equipment (excluding LTC compartments, oil expansion tanks, etc.) It lists the following as useful information to calculate loss of life: Load loss at rated and tap extremes or all possible tap connection combinations, winding resistance at tap extremes or all possible tap combinations total stay and eddy loss as a percent of total load loss and estimated stray and eddy loss, and per-

unit winding height to hot-spot location. The presentation also lists necessary adjustments needed to achieve more accurate capability predictions based on the actual load cycling and tap connections. The adjustments are based on load cycle in kVA on the actual combination of tap connections. The process is then to use the measured or calculated load losses for that tap connection, correct the temperature rise data for the lower losses or different rated current, and determine if the hottest-spot winding gradient changes with changes in the tap connections.

Any of the following may limit the loading to less than the capability of the winding insulation: Oil expansion, Pressure in sealed units, Thermal capability of bushings, Leads, Tap changers, Associated equipment - cables, reactors, circuit breakers, fuses, and disconnecting switches, current transformers. Also, operation at honest-spot temperatures above 140 °C may cause gassing in the solid insulation and the oil. Suggested limitations: Top Oil temp = 120 °C, Honest spot = 200 °C, Short-time loading = 300 % (1/2 hour or less).

The report provides a table of loss of life expectancy from short time loading with hot-spot temperatures above 110 °C.

The section on contingency and spares planning provides a conceptual overview of planning for contingencies and spares and monitoring. It also provides detailed lists of inspection, tests, and diagnostics for transformers, cables, and power systems.

Monitor power transformers for: Liquid level, Load current, Temperature, and Voltage. Perform the following inspections and tests on power transformers: Exterior for signs of damage & deterioration, Interior for signs of damage & deterioration, Check Ground connections, Lightning arresters, Protective devices and alarms, Radiators, pumps, valves and fans, Tap changer function, Other exterior ancillary devices.

Perform the following inspections and tests on power transformers solid insulation: Hi-pot (AC), Induced voltage, Insulation resistance, Power factor, Polarization index & recovery voltage, Perform the following inspections and tests on power transformers Insulating oil: Acidity, Color analysis, Dielectric strength, Interfacial tension, Power factor, TCGA, Perform the following inspections and tests on power transformers when condition is suspect: All inspections and above tests, TCGA (Gas chromatography), Insulation resistance, TTR

The following inspections and tests are suggested for cables (test and purpose are listed): Visual Inspection, Check for visible deterioration; leaks corrosion., Indentor Test, Track material deterioration; Insulation Resistance, Non-destructive test of insulation quality; PD Test, Detect flaws/incipient failures, High stress; Hi-potential (DC), Detect flaws/incipient failures, Very high stress; and Fault location, Identify failure location.

The following additional inspection and tests are suggested for the power system: Thermal load, Resistance, Dielectric, Absorption, Power Factor, Polarization recovery., Hi-pot, Induced, Partial, Discharge, Transformer Turns Ratio, Oil acidity, Interfacial, TCGA, DGA, Disassembly/ Inspection.

On page 4 of the Aging Equipment and Its Impacts section there are three small graphs showing failure rates. No information is provided on sample size or time period for collection. Graph 1 shows failures per year versus age in years for 25-kV solid, 15-kV solid, 25-kV paper, and 15-

kV paper cable sections. Graph 2 shows failures per year versus age in years for 25-kV solid, 15-kV solid, 25-kV paper, 15-kV paper, 25-kV solid-paper, 15-kV solid-paper cable joints. Graph 3 shows failures per year versus age in years for 25-kV and 15-kV pad-mounted transformers.

On page 12 of the Aging Equipment and Its Impacts section the graph regarding pad-mounted transformers in shown in larger scale.

On page 6 of the Transformer Loading and Loss of Life Determination section there is a equation for the per unit insulation life with specified parameters. Independent variable is the winding hottest-spot temperature.

On page 7 of the Transformer Loading and Loss of Life Determination section there is a equation for the Aging Acceleration Factor or Faa and Feqa the equivalent life consumed in given time period for a given temperature cycle with specified parameters Faa and Feqa are used to calculate the equivalent age and percent loss of total life of a transformer. The independent variables are the winding hottest-spot temperatures and duration at each temperature.

On page 8 of the Transformer Loading and Loss of Life Determination section there is a equation for the percent loss of total life with specified parameters. The independent variables are Feqa, the normal insulation life, and the age of the transformer.

On page 10 of the Transformer Loading and Loss of Life Determination section there is a Table describing the of ambient temperature on loading and aging. Rows of the table indicate the type of cooling, The first column is the decrease in loading as a percent of kVa rating needed to preserve normal life expectancy for each one degree C increase in ambient temperature. The second column is the increase in loading as a percent of kVa rating allowed to preserve normal life expectancy for each one degree C decrease in ambient temperature.

On page 14 of the Transformer Loading and Loss of Life Determination section there is a Table describing the loss of life expectancy from short periods of loading at higher than normal hottest-spot temperatures. Columns are times, rows are % loss of life, and entries are temperatures.

On page 17 of the Transformer Loading and Loss of Life Determination section there is a Table describing limits on loading stated as temperatures. Rows of the table refer to insulated conductor hottest-spot temperature, other metallic hot-spot temperature, and top oil temperature. Columns refer to normal life expectancy loading, panned loading beyond name plate, long-time emergency loading, short-time emergency loading.

The following references may be of interest. H.L. Willis, Power Distribution Planning Reference Book, Marcel Dekker, Inc., 1997; H.L. Willis, Aging Power Delivery Infrastructures, Marcel Dekker, Inc., 2001; Paul Gill, Electrical Power Equipment Maintenance and Testing, Marcel Dekker, Inc., 1998

Search terms and ID: Multiple, Data, Equations, Presentation, 62

Alexander, 1994

Alexander, Harold; Rogge, Dan

"Harmonics: causes, problems, solutions.(part 2)," EC&M Electrical Construction & Maintenance, 1994, February, Intertec

Discusses the problems caused by harmonics and presents some approaches to reducing harmonics. Has an extensive reference list. The article does not discuss the relationship of harmonics to aging, nor is there any discussion of economic consequences of harmonics.

Harmonics can cause:

- Overheating in transformers
- Problems with power factor
- Blown fuses and disfigured capacitors
- Fuses overheat and have nuisance tripping
- Problems with inverse time circuit breakers
- Problems with protective relays

Search terms and ID: Multiple, Causes, Design, Journal Article, 55

Allan, 1995(1)

Allan, D.J.; White, A.

"Transformer Design for High Reliability," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 66-72, IEE, Norwich, UK

Design of transformers is being increasingly guided by cost of ownership. This paper discusses how manufacturers are increasing dependability and reliability to reduce the cost of ownership.

Paper focuses on design topics, but there is ample data regarding transformer failures. Table 1 displays the main causes of failure to transformers in service (CIGRE survey). Table 2 displays a list of components causing failure in service (CIGRE survey)

Search terms and ID: Transformers, Design, Causes, Proceedings, 68

Allan, 1995(2)

Allan, R.N.; Billinton, R.

"Concepts of Data for Assessing the Reliability of Transmission and Distribution Equipment," Reliability of Transmission and Distribution Equipment, The, 1995, 29-Mar, 406, 6-Jan, IEE, Norwich, UK

Paper discusses the concept of data and the data necessary for analysis, modelling and predictive assessments. Data can be used for assessment of past performance and/or prediction of future performance. Failure processes, such as short circuit failures, open circuit failures, switching failures and environmental failures, are also discussed.

General discussion of data. No actual data is presented.

Search terms and ID: System, Data, Causes, Journal Article, 83

Allan, 1983(1)

Allan, R.N.; Avouris, N.M.; Kozlowski, A.; Williams, G.T.

"Common Mode Failure Analysis in the Reliability Evaluation of Electrical Auxiliary Systems," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 132-136, IEE, London, United Kingdom

This paper discusses four types of failures that have been simulated to assess the reliability of electrical auxiliary systems. The models incorporate the effect of common failures of auxiliary systems, and the paper concludes that in one of the models presented that common mode failures had a considerable effect on busbar unavailability.

This paper mostly discusses mathematical equations for failure sequences. Data is provided for a sample system, but the data appears to be hypothetical and system components are not well identified.

Search terms and ID: System, Technical, Proceedings, 8

Allan, 1983(2)

Allan, R.N.; De Oliveira, M.F. ; Chambers, U.A.; Billinton, R.

"Reliability Effects of the Electrical Auxiliary Systems in Power Stations," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 28-31, IEE, London, United Kingdom

Provides calculations for comparing alternative designs, quantify reliability, and identify possible failure modes. Calculations are based upon incorporating realistic failure modes and restoration procedures involving main, guaranteed and essential systems. Alternative designs that meet reliability criteria can than be compared on a cost to benefits basis.

Table 1 provides the following data: Total Failure Rate, f/yr; Active Failure Rate, f/yr; Repair Time; Stuck Probability; Maintenance Time; Maintenance Rate; and Switching time (columns). The components in rows are designated in a circuit diagram. The source of the data is not provided. This article mostly discusses busbar reliability and provides a table of busbar reliability.

Search terms and ID: System, Technical, Data, Journal Article, 11

Allan, 1983(3)

Allan, R.N.; De Oliveira, M.F.

"Reliability Analysis in the Design of Transmission and Distribution Systems," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 58-61, IEE, London

This paper discusses restoration models that follow point load failures that can be identified from component outage modes for distribution and transmission systems. Multiple approaches for evaluating reliability are presented and their individual merits discussed.

The source of the reliability data is not referenced. Table 2 presents reliability data for busbars, breakers, transformers, and lines (rows). Data presented (columns) includes: total failures/year, active failures/year, temporary failures/year, maintenance outages per year, repair time, switching time, reclosure time, maintenance time, stuck probability.

Search terms and ID: Multiple, Technical, Proceedings, 12

Allen, 1995

Allen, J.N.

"System Reliability Improvement--An Australian Experience," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 139-144, IEE, Norwich, United Kingdom

Description of implementation of strategies to improve system performance and improved service to an Australian utility. Total Quality Management and Quality Task Teams are discussed.

Figures present the causes and effects of failure for 11 kV feeder faults. Other figures display a historic reliability index, a "fishbone" diagram of failure root causes of 11 kV feeder faults. Further figures provide data regarding lost energy sales, causes of failures, failed components, and historic reliability. The measure for historic reliability is minute/customer/annum.

Search terms and ID: System, Design, Data, Proceedings, 71

Allison, 1995

Allison, M.R.; Lewis, K.G.; Winfield, M.L.

"Integrated Approach To Reliability Assessment, Maintenance and Life Cycle Costs in the National Grid Company, An," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 180-185, IEE, Norwich, UK

Discussion of maintenance and asset replacement strategies and techniques based on the behavior and performance of the equipment involved. Maintenance policies, asset replacement and transmission system reliability are discussed.

Figure 1 displays failure rate percentages per year (1982 through 1993) for 400 kV circuit breakers. Data regarding plant equipment installation dates and other qualitative data is presented.

Search terms and ID: Multiple, Maintenance, Data, Proceedings, 75

Arceri, 1976

Arceri, John A.

"Statistical Analysis and Review of Underground Distribution Systems and Equipment," IEEE Conference Record - Supplement 1976 Underground Transmission and Distribution Conference, 76 CH1119-7-PWR (SUP), 1976, Sept. 27-Oct. 1, 34-38, IEEE

Paper displays underground distribution system and equipment data from 38 major utilities.

Background data is presented regarding the utilities represented by the data and expected failures/100 miles/year due to dig-ins. Figures 8 and 9 display graphs of average new installations per year per utility as a function of time (years). Figure 10 displays failure rates for direct buried primary cables. Figure 11 is similar to Figure 10, but failure rates are presented as a function of cable depth. Figure 12 displays annual failure rate per year for primary molded elbows. Figure 13 displays annual failure rate per year for primary molded splices. Figure 14 displays annual failure rate per year for pad-mounted and below grade single phase transformers. Figure 15 displays annual failure rate per year for pad-mounted three phase transformers. Figure 16 summarizes the data from the article in terms of failure rates of underground equipment and overhead equipment.

Search terms and ID: System, Data, Causes, Journal Article, 101

Atkinson, 1987

Atkinson, W.C.; Ellis, F.E.

"Electricity distribution asset-replacement considerations," Electronics & Power, 1987, May

The paper describes the age distribution of key distribution assets in the power system of England and Wales. It notes that age alone does not determine the need for replacement. Factors such as: original design, materials used, environment, loading, maintenance, technology, and suitability for refurbishing affect the need for replacement. Discusses issues such a monitoring, technology change, typical installations, and other issues surrounding each type of equipment.

Search terms and ID: Multiple, Monitoring, Maintenance, Journal Article, 222

Barber, 1995

Barber, Fred; Hilberg, Gary

"Comprehensive maintenance program ensures reliable operation," Power engineering, 1995, December, 99, 12, 27

Provides some background on common preventative maintenance (PM) practices at Independent Power Producers' (IPP's) generators. Describes the PM program at North American Energy Services in some detail. Notes that most IPP's use computerized maintenance systems.

Search terms and ID: Generators, Maintenance, Journal Article, 206

Bargigia, 1991

Bargigia, A ; Heising, C.R.

"High Voltage Circuit Breaker Reliability Data For Use In System Reliability Studies," CIGRE Symposium on Electric Power System Reliability, Montreal 1991, 1991, September 16-18, 1-6, CIGRE

"This articles summarizes two international studies on high-voltage circuit breakers. First, there are data on 20000 miscellaneous breakers from 1974-1977, an effort that involved 102 utilities in 22 countries. Second is data on 16500 of the newer technology single-pressure SF6 breakers from 1988-1989, which is the first half of a 4-year study involving 100 utilities in 18 countries. It presents raw data failure rates for a number of failure modes and calculated probability results that can be used in system reliability studies. The Working Group includes definitions of the different events. The possible failure modes include not responding to an operating command. The combination of the results from the two studies covers both older technology circuit breakers and the newer SF6 circuit breakers for system reliability studies.

Discussion of data collected from two studies regarding circuit breakers. World-wide reliability data was collected for 63 kV and above circuit breakers in greater detail than typical for system reliability studies. Reliability was based on the following failure types: 1) Failure; 2) Major Failure; 3) Minor Failure; 4) Defect; and 5) Circuit Breaker Downtime."

Table 2 - Failure rates and downtime data for high voltage circuit breakers above 63 kV. Rows: All voltages, 63<V<100, 100<V<200,200<V<300, 300<V<500, 500<V. Columns: Major failures sample size-breaker years, Number of major failures, Major failures per breaker year, Major failures Hours downtime per failure average and median, Minor failures sample size-breaker years, Number of minor failures, minor failures per breaker year.

Table 3 - Major failure modes of high voltage circuit breakers. Rows are failure modes. Columns are breaker sizes. Entries are percentage of failures.

Table 4 - Estimated average number of operating-cycles per year per breaker. Rows are percentiles. Columns are breaker sizes. Entries are number of operating-cycles per year per breaker.

Table 5 - Reliability data on high-voltage circuit breakers above 63 kV that can be used in system reliability studies. Entries are failure rates. Rows are breaker sizes. Columns are: Does not open on command, does not break the current, does not close on command, does not make

the current, major failures per operating cycle, average number o operating cycles per year, major failure per breaker year during command, major failure per breaker year without a command, Total major failure per breaker year.

Table 6 - Failure rates and downtime data for single-pressure high-voltage circuit breakers above 63 kV. Rows: All voltages, 63<V<100, 100<V<200,200<V<300, 300<V<500, 500<V. Columns: Sample size-breaker years, Number of major failures, Major failures per breaker year, Major failures Hours downtime per failure average and median, Number of minor failures, minor failures per breaker year.

Table 7 - Major failure modes of single-pressure high-voltage circuit breakers. Rows are failure modes. Columns are breaker sizes. Entries are percentage of failures.

Table 8 - Estimated average number of operating-cycles per year per single-pressure breaker. Rows are percentiles. Columns are breaker sizes. Entries are number of operating-cycles per year per breaker.

Table 9-Table 5 - Reliability data on single-pressure high-voltage circuit breakers above 63 kV that can be used in system reliability studies. Table structure identical to Table 5.

Table 10 - Same as Table 9, except that Major Failures per Operating Cycle could be increased by with the assumption that each locking in open or closed position failure resulted from one command to open or close."

Search terms and ID: Switches, Data, Journal Article, 49

Basille, 1995

Basille, C.; Aupied, J.; Sanshis, G.

"Application of RCM to High Voltage Substations," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 186-191, IEE, Norwich, United Kingdom

Reliability Centered Maintenance (RCM) adopts probabilistic and Bayesian techniques to take criticality into account. Efficiency, cost, and operational discomfort are taken into account in improvements based on reliability. Various system personnel are able to combine knowledge in this framework.

Pilot study conducted on a 400 kV line bay. Task selection, decision principles and influence of maintenance on failures are expressed in diagrams. No quantitative data is presented.

Search terms and ID: System, Technical, Proceedings, 76

Baxter, 1988

Baxter, M.J.; Bendell, A. ; Manning, P.T.; Ryan, S.G.

"Proportional hazards modeling of transmission equipment failures," Reliability engineering and system safety, 1988, 21, 129-144, Elsevier, Great Britain

"The paper applies Proportional Hazard Modeling (PHM) to two subsets of the Central Electricity Generating Board (CEGB), UK, transmission failure and repair database and investigates the influence of external variables on the failure and repair data. Proportional hazards modeling (PHM) is a technique for ensuring that assumptions used in reliability models are compatible with the data structure. The objectives of the paper may be summarized as: to ascertain the relevance of PHM towards the analysis of the transmission reliability data, to compare and contrast the results for disparate geographical areas, and to determine the validity of the reliability models in current use.

The paper starts by introducing PHM, which describes the relation between hazard rate and a set of external variables, as the exponential of a linear combination of the external variables multiplied by a base-line hazard function (hazard rate is a function of time whose integral within a given interval gives expected number of failures in that interval). The authors attempt to provide a way to test the effect of additional variables, such as weather, on the hazard rate. Base-line hazard function is equivalent to hazard rate function if all external variables are equal to zero and the rest of the paper deals with a distribution free approach where the base-line hazard function is non-parametrically estimated from data.

The authors introduce the application section with a word of caution that PHM, just as any other reliability analysis technique, not be used as an automatic black-box method but rather in an exploratory mode, with repeated applications of varying formulations in order to identify and focus explanatory power on the failure processes involved. The authors conclude that the ability to investigate all potential variables (provided by PHM exploratory advantage) for which either a proper numerical or classification is available in the data is a major advantage, rather than having to rely, as in more traditional reliability analysis, on implicit assumptions of homogeneity. In the particular context of CEGB transmission systems, the method has confirmed its relevance and power providing results of similar causal structure, and parameter estimates of similar size, in disparate geographical areas.

Data is from the transmission system of the Central Electricity Generating Board (CEGB) in England and Wales. Data on faults for this system has been collected since 1996 however the precise period for this data is not presented. There was also no information on the number of components covered by the data. Table 2 presents data on lines, circuit breakers, protection equipment, transformers, and isolators (Rows). Columns are total number of faults and potential causes. Causes include weather, season, environmental (cause), and voltage. Entries are counts. A total of 1747 faults are considered.

In two other tables time between faults and restoration times are considered for the same equipment.

Overhead line failures had greatest impact on system reliability. Weather, season, and time are significant. The pattern of failure is not random, but they occur in "bunches" linked to adverse environmental conditions (chances of faults due to environmental conditions are 1000 times higher than under normal conditions).

The covarients presented in the article are weather, season, cause, voltage and time.

For PHM to be worthwhile, there needs to be a lot of data. The technique worked well for overhead lines in this article because there was plenty of relevant data.

A lot of data is presented, but it is all in the context of PHM models."

Search terms and ID: Multiple, Technical, Data, Journal Article, 59

Beaty, 1997

Beaty, Wayne

"Transmission systems struggle to keep pace with growth," Electric light & power, 1997, May, 75, 5, 18

Wide ranging discussion of the current status of U.S. transmission systems. Covers difficulty of line construction, technical solutions for transmission reliability problems, and maintenance.

Search terms and ID: System, Design, Maintenance, Journal Article, 209

Beaty, 1995

Beaty, Wayne

"Maintenance is key to competitiveness and reliability," Electric light & power, 1995, June, 73, 6, 32

Discusses several trends in monitoring and maintenance of distribution systems. These include: the use of inspection services, robotics, and vegetation management.

Search terms and ID: System, Monitoring, Maintenance, Journal Article, 212

Begian, 1972

Begian, Sam S.

"Data Collection System for Analyzing Transmission and Distribution Performance," 1972, 1-4, IEEE

Paper describes a method to gather, distribute and analyze outage data.

Qualitative description of a data collection system. No data is presented.

Search terms and ID: System, Data, Causes, Journal Article, 103

Berg, 1997

Berg, Menachem

"Performance Comparisons for Maintained Items," Mathematical Methods of Operations Research, 1997, 45, 377-385, Physica-Verlag, Heidelberg, Germany

Focus of the paper is on the improvement in performance that results from a maintenance action. Different modeling situations are considered, and for each of them conditions are obtained on the life distribution of the present item and the new one if of different type, that ensure performance improvement. The paper also deals extensively with probabilistic ordering notions and aging properties. The paper is theoretical and does not provide numerical examples.

High level theoretical paper. No indications of applications.

Search terms and ID: Non-specific, Financial, Technical, Journal Article, 201

Berg, 1995

Berg, Menachem

"Age-Dependent Failure Modeling: A Hazard-Function Approach," 9569, 1995, June, Center for Economic Research

Paper presents a mathematical tool for age-dependent failure modeling that separates assets into two categories: those discarded upon first failure and those that are repaired. For those assets discarded after first failure, the hazard function is a function of failure mechanism and life distribution. There can only be one failure mechanism, which is dependent on age. The author discusses mathematical functions that describe failure mechanisms and that the reliability of such mechanisms is dependent on goodness of fit, flexibility, and lack of sufficient data. For repairable systems, the author states that age is not the only necessary data.

The paper includes discussions of hazard rate ordering. Aging characteristics belong in the realm of the single-fault case since they depend only upon the age of the asset. Modeling of age-dependent failure mechanisms is better when hazard functions are used.

Search terms and ID: Multiple, Technical, Report, 21

Billinton, 1995

Billinton, R.; Ghajar, G.; Filippelli, F.; Del Bianco, R.

"Transmission Equipment Reliability Using the Canadian Electrical Association Information System," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 13-18, IEE, Norwich, United Kingdom

Canadian data from 1988 to 1992 regarding the reliability of power distribution components, with data subdivided into voltage categories.

"Data is from the period 1/1/1988 to 12/31, 1992, Canadian Electrical Association Equipment Reliability Information System (CEA-ERIS). Data is for 110kV to 799kV divided into 6 classes by size. Tables for transmission lines and cables (Tables 1 and 2) provide outage frequency, mean duration and percent unavailable data. Tables for transformers, circuit breakers, synchronous compensators, shunt reactors, shunt capacitors, and series capacitors (Tables 3, 4,5, 6,7, 8, and9) provide frequency and mean duration.

We have a copy of the full report for the 1/1/1992 to 12/31/1996 period. "

Search terms and ID: Multiple, Data, Proceedings, 64

Billinton, 1993

Billinton, R.; Gupta, R. ; Chowdhury, N.A.; Goel, L.

"Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference 1993, 1993, March 18, 37-42

Paper presents computer programs that help perform reliability assessments for subtransmission and radial distribution configurations. The programs allow for faster computation and sensitivity analyses in systems with increasing components. Some sample data for components is presented.

The calculations are performed on a reliability test system designated as the RBTS. No data sources are specified other than this system. References for the system are listed. The reliability data is found in Table 4. Components (rows) are Transformer, breakers, busbars, and lines.

Failure data (columns) include: Permanent failure rate, Active failure rate, Temp. failure rate, maintenance outage rate, Repair time, Maintenance time, Reclosure time, Switching time.

Search terms and ID: Multiple, Technical, Data, Proceedings, 52

Billinton, 1987

Billinton, C.J.; Billinton, J.E.; Billinton, R.

"Service Continuity Performance of Canadian Electric Power Utilities - A Historical Perspective," Proceedings of the 14th Inter-RAM Conference for the Electric Power Industry, Toronto, Canada, May 1987., 1987, May, 456-463

Canadian electric power utilities have collected service continuity statistics for over twenty years. These statistics show that the participating utilities 'have an excellent record of service continuity performance. The collection procedure has undergone many changes since It was initiated in 1961 and has now evolved into a useful and important indicator of both individual utility and national service continuity performance. This paper traces the evolution of this system and the participation of Canadian utilities. The contribution to the service continuity statistics of such factors as loss of supply, adverse weather and defective equipment is illustrated.

The paper presents interesting statistics on index of reliability and SAIFI overtime and for individual utilities. It also presents interesting data regarding the causes of customer outages. However, it presents no component level data.

Search terms and ID: System, Data, Proceedings, 259

Billinton, 1978(1)

Billinton, Roy

"Transmission System Reliability Models," Workshop Proceedings: Power System Reliability--Research Needs and Priorities, WS-77-60, 1978, March 5-9, 2-10 through 2-17, EPRI

Author begins by describing the need for, and absence of, adequate transmission system reliability models. A basic model for common cause failures is presented and discussed. A discussion of the need for realistic common-cause models is also included.

Some failure probability data is presented for hypothetical models. Paper presents little in terms of aging asset failure data or models.

Search terms and ID: Non-specific, Model, Data, Report, 114

Billinton, 1978(1)

Billinton, R.; Medicherla, T. K. P.; Sachdev, M. S.

"Common Cause Outages in Multiple Circuit Transmission Lines," IEEE Transactions on Reliability, 1978, June, R-2, 5, 128-131, IEEE

Reliability evaluation of a power system involving both generation and transmission elements is extremely complex. Outages of these elements are usually considered to be s-independent events. Recent investigations, however, have indicated that common-cause outages of multicircuit transmission configurations can appreciably affect the predicted reliability. Closed form expressions for steady state probabilities in 2- and 3-line cases (including certain common-cause failures) are developed. These expressions provide transmission-line state probabilities for composite generation and transmission system reliability studies. The procedure can also be used to develop state probabilities for other line models and for systems with four or more lines on the same right-of-way. The examples show the influence of the common-cause outage rate on the state probabilities. There is a definite need to include common-cause outages in reliability evaluation of transmission systems. This will require a more comprehensive approach to collecting transmission line outage data than has previously been used by most utilities.

Table 1 reports outages/100 miles-year and repair duration in hours for 69, 138, 161, 345, and 500 kV lines. The data is based on the summer line outage experience of Oklahoma Gas and Electric Company. Lightning outages are uncommon in Oklahoma during the summer and therefore the outage rates do not include outages due to lightning. No other information is presented on the outage data.

Search terms and ID: System, Technical, Data, Journal Article, 248

Billinton, 1976

Billinton, Roy; Crousse, John H. T.; Miller, W. T. ; Pontifex, C. E.; Troalen, P. ; Wicentovich, M. N.

"Distribution System Reliability Engineering Guide," 1976, March, 105, Canadian Electricity Association

The reliability engineering guide provided by the CEA has the fundamental series-parallel reduction modeling information that has been in place for over 25 years. It states that there existed at the time of writing a suitable methodology for predicting reliability indices, but component outage data has lagged behind. The initial reliability indices defined were customer-hours of interruption and kVA-hours of interruption, before frequency and duration. The indices defined here are SAIFI, CAIFI, SAIDI, CAIDI, ALII, ASCI, and ACCI, as contained in an early IEEE standard (# 346-1973). The guide discusses reliability criteria based on outage frequency, average duration, and expected annual outage time can be used to assess continuity. The appendices illustrate a number of calculation examples for predictive reliability assessment of small portions of systems, including one example comparing 2 alternatives considering reliability worth.

The report provides very little data. The data provided is to illustrate example calculations. References for the data are generally not provided.

On page 19, a table of Maximum Actual Restoration Time is provided. The data is from the period 1969 to 1973. Columns of the table indicate component involved, time when personnel on duty, time when sectionalizing available, all other cases. Rows cover Substations of different sizes, Substation bus sections, and circuits.

Page 39 there is illustrative failure data for a manually sectionalized primary main.

Page 44 there is illustrative failure data for a 46-kV substation.

Page 47 there is illustrative failure data for a distribution substation.

Page 49 there is illustrative failure data for a subtransmission system."

Search terms and ID: System, Technical, Data, Report, 218

Blaicher, 1975

Blaicher, Herbert E.

"Open Forum: Equipment Failure Reporting Systems," Undergrounding, 1975, January/February

Article presents interviews with four industry practitioners regarding their efforts in implementing failure reporting systems.

No data is presented.

Search terms and ID: Non-specific, Other, Journal Article, 124

Brint, 2000

Brint, A.T.

"Sequential inspection sampling to avoid failure critical items being in an at risk condition," Journal of the Operational Research Society, 2000, Sept, 51, 9, 1051-1059, Stockton Press for the Oper. Res. Soc, The problem of how to extend the time interval of fixed time period maintenance for items whose failure can be catastrophic, is considered. The paper proposes a coherent methodology particularly applicable to switchgear used within electricity distribution networks. The methodology involves taking a sample of the items and based on their observed conditions, deciding whether to: maintain, defer maintenance, or take another sample. Consideration of the precise problem to be solved leads to a Bayesian formulation. The predictive distribution is then used to determine the expected outcome of taking further observations. Results using simulated and real data are reported. This sequential sampling approach seems particularly appropriate for distribution networks where inspection costs can be relatively high.

The real data reported is the moisture level within switches. An arbitrary maximum moisture level is defined.

Search terms and ID: Switches, Technical, Journal Article, 239

Brown, 2001

Brown, R.E.

"Probabilistic reliability and risk assessment of electric power distribution systems," Distributech 2001, 2001

To provide high levels of customer reliability for the lowest possible cost, utilities must plan and engineer the reliability of distribution systems. Just as capacity engineering requires tools to predict currents and voltages based on loading data, reliability engineering requires tools capable of predicting interruption characteristics based on component reliability data. This paper presents an analytical simulation that can represent detailed reliability characteristics, is computationally efficient and is suitable for computing expected values related to momentary interruptions and sustained interruptions. The analytical simulation is then extended into a hybrid analytical/Monte Carlo simulation that is more computationally intensive, but is capable of producing a probability distribution of annual reliability behavior that is suitable for risk analyses. Characteristics and capabilities of these two methodologies are demonstrated on a distribution system subject to performance based rates.

No data is reported on specific equipment.

Search terms and ID: System, Financial, Proceedings, 265

Brown, 2000(1)

Brown, R.E.; Howe, B.

"Optimal deployment of reliability investments," The Power Quality Series, 2000, April, PQ-6, E source

Describes the current distribution system planning environment, utility and customer financial impacts of poor reliability, traditional approaches to estimating system reliability indices such as SAIDI, analytic approaches to calculating the value of system upgrades or optimizing system designs, and case studies of projects to upgrade system reliability. The report argues that performance based regulation, liability to customers for losses due to outages, and other factors are increasing the importance of distribution system reliability. The report argues that utilities need to examine utility and customer costs and evaluate distribution system maintenance and replacement projects based on the minimization of these costs. The next section discusses specific technical approaches to estimating system reliability and costs. The final two sections present two case studies: the first looks at five alternatives for improving the reliability of the distribution system for an oil refinery and the second looks at alternative to improving reliability in a neighborhood in a quickly developing urban area.

No data is reported on specific equipment.

Search terms and ID: System, Financial, Other, Report, 262

Brown, 2000(2)

Brown, R.E.

"Impact of heuristic initialization on distribution system reliability optimization, The," Engineering Intelligent Systems, 2000, March, 8, 1, 29-36, CRL Publishing

Deregulation of the electricity market is, ironically, resulting in more regulation on distribution systems. Regulators, fearful that cost cutting will result in reduced reliability, are using performance-based rates to penalize utilities if reliability deteriorates. A distribution system subject to performance-based rates has an optimal configuration that best balances equipment cost and reliability penalties. This paper develops and compares several algorithms capable of optimizing distributions systems in this context. The basic form of each algorithm (integer programming, simulated annealing, and genetic algorithms) uses random solutions for initialization. This paper examines the impact of replacing random initialization with initialization based on heuristic knowledge encoded into fuzzy rules. Genetic algorithms with heuristic initialization are shown to outperform other optimization methods.

This is a highly technical paper focused on the performance of specific mathematical optimization techniques in estimating the reliability of different distribution system designs. Table 3 provides the failure information for a test system used to compare the optimization techniques. Data is provided (in rows) for overhead lines, underground cables, reclosers, fuses, manual switch, and automated switch. The data (in columns) include failure rates, mean time to repair, mean time to switch, and probability of operational failure.

Search terms and ID: Multiple, Financial, Data, Journal, 263

Brown, 1998

Brown, R.E.; Ocha, J.R.

"Distribution System Reliability: Default Data and Model Validation," IEEE Transactions on Power Systems, 1998, May, 13, 2, 704-708, IEEE

A method for determining appropriate component reliability values is presented that matches predicted indices to historical indices. This is necessary because most utilities do not have sufficient historical data to adequately represent their system in a reliability analysis. This validation method presents a way of gaining confidence in a reliability model. The method is applied to parameters such as MAIFI, SAIFI, SAIDI, etc.

Initial failure rate data come from the RBTS, test system developed by R. Allan, R. Billinton, I Sjarief, L. Goel, and K. So. (See "A Reliability Test System for Educational Purposes-Basic Distribution System Data and Results, " IEEE Transaction on Power Systems, Vol.6, No. 2, May 1991, pp. 813-820 by the listed authors.) Table 1 provides data for feeders, reclosers, fuses, switches, STS (rows). Data provided are Sustained failure rate, Momentary failure rate, Mean time to repair, Probability of successful switching (columns). Case studies are presented. Line failure rates are a function of vegetation, tree trimming, weather, etc., so previously published representative data is difficult to apply to other systems. MAIFI an SAIFI are predominantly affected by overhead lines.

Search terms and ID: Multiple, Technical, Data, Journal Article, 43

Bucci, 1994

Bucci, R.M.; Rebbaragada, R. V.; McElroy, A. J.; Chebli, E. A.; Driller, S.

"Failure Prediction of Underground Distribution Feeder Cables," IEEE Transactions on Power Delivery, 1994, October, 9, 4, 1943-1955, IEEE

This paper presents a methodology to determine an age-related reliability index that can be used to compare the relative likelihood of in-service failures among underground distribution feeders. It was developed for the Con Edison 27 kV and 13.8 kV distribution systems but is sufficiently generic to apply to any group of underground distribution feeders. Each feeder is represented by a combined reliability model of its individual components, including the following: cable sections-paper and solid dielectric insulated cables; cable joints-paper-to-paper, paper-to-solid dielectric and solid dielectric-to-solid dielectric insulated cable joints; and network transformers. The parameters of each component model are determined based upon historical failure data according to age. The confidence level associated with the prediction is also determined, and a brief description of the computer program developed and its application to Con Edison's Yorkville 13.8 kV primary distribution network are provided.

Several equations are presented to discuss the analytical basis for the model. Table 1 displays the quantity of failed components of age 5 or less, greater than 5 years, and unfailed components at the end of the study window. The table displays the number of failures of transformers, paper cables, solid cables, paper paper joints, paper solid joints, and solid solid joints for 13.8 kV and 27 kV systems. Tables 2 and 3 expand upon the data in Table 1 for failed components f age 5 years or less or greater than 5 years, respectively. Beta (shape parameter) and lambda (scale parameter) data for Weibull distributions are presented. Figures 2 and 3 display actual and Weibull curves for the percentage of failures versus age at failure for 13.8 kV cable OA/FOT paper insulation and 13.8 kV OA/FOT solid solid, respectfully. Table 3 displays distribution feeder outage prediction data from the software package that performs the calculations for the model presented in the paper. The data presented include the feeder component number and the quality reliability index for transformers, cables, joints and the feeder age-related reliability index with 90% confidence limits. Appendix A contains a discussion regarding the journal article where more equations are presented. Figure 4 is also displayed as a comparison of near-term predictions of Equation 12 (from the paper) versus alternatives. Data from the initial estimate, test case, equation 12, and IEEE estimate are presented.

Search terms and ID: Cables, Technical, Equations, Journal Article, 93

Burges, 1983

Burges, L.H.

"Benefits of Quantitative Analysis in the Assessment of Electrical System Reliability," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 7-12, IEE, London, United Kingdom

This article discusses the benefits of quantified reliability analysis. It looks specifically at systems configuration and whether or not it will meet some predetermined target reliability. Looks at reliability parameters such as causes of faults, is a particular piece of equipment more prone to failure than others, etc.

The article outlines a methodology, and has very brief comments regarding trip relays. Uses a failure rate of trip relays of 0.05 faults/year.

Search terms and ID: System, Technical, Data, Proceedings, 10

Cabane, 1973(1)

Cabane, E.; Carton, D.; Denoble, R.; Guillevic, A.; Latil, L.; Michaca, R.

"Reliability of switchgear and transformers in distribution substations," CIRED 2nd International Conference on Electricity Distribution, 1973, 36-48, IEE, London, UK

Two separate issues are addressed in this paper. In part one, failures in metal-enclosed switchgear are examined. The issue is the appropriate rate of maintenance considering the cost of maintenance and cost of undelivered energy. It begins with a review of stresses on switchgear. It then presents costs and failure rate information and calculates the cost of alternative maintenance strategies. Part two reports on tests of new 25, 50, and 100 kVA transformers. These transformers were subjected to impulses of 47.5 kV up to 160 kV to test their response to lightning impulses. The failure rates and equations for probability of failure are reported and compared to earlier designs.

In Part one, fault rates on feeders are listed. These are for a 70 km feeder fugitive faults 74/year, semi-permanent faults 10/year, and permanent faults 5/year. The breaker failure rate is 0.023 failures/year. Data sources or other details are noted provided. Part two presents failure data for the new transformers tested in detail. Based on the data they present equations for failure probabilities given the transformer rating and the impulse size.

Search terms and ID: Multiple, Technical, Data, Proceedings, 228

Cabane, 1973(2)

Cabane, E.; Carton, D.; Denoble, R.; Guillevic, A.; Latil, L.; Michaca, R.

"Reliability of switchgear and transformers in distribution substations," CIRED 2nd International Conference on Electricity Distribution, 1973, 36-48, IEE, London, UK

This paper begins with a review of the stresses on metal-enclosed switchgear in distribution substations. It then discusses the costs associated with this equipment including maintenance, repairs, undelivered energy costs. In the next section it examines transformers and tests that can be performed on transformers to assess their condition.

Provides data on the failures of transformers under application of high-voltages.

Search terms and ID: Switches, Causes, Monitoring, Proceedings, 266

Call, 1991

Call, H.J.; Beccue, P.C.; Murphy, D.A.

"Diagnosis and Treatment of Component Failure Using Bayesian Inference," Use of decision analysis model for making decisions under uncertainty is discussed for choosing whether or not to replace boiler tubes. Bayesian calculations are performed with DPL decision analysis software.

Qualitative description of quantitative methods. Examples of influence diagrams and decision tree diagrams are presented. For data generated by the analysis, Figure 8 displays life fraction distribution with priors and test results and Figure 9 displays expected value costs versus the service age of tubes.

Search terms and ID: Other, Technical, 84

Carr, 1992

Carr, J.; Godfrey, R.M.

"UNDERGROUND VERSUS OVERHEAD DISTRIBUTION SYSTEMS," CEA No. 274 D 723, 1992, October, CANADIAN ELECTRICAL ASSOCIATION, Montréal, Québec

The selection between underground and overhead distribution systems is often based only on a comparison of the first costs. This report presents data and analysis techniques that incorporate all life cycle costs in the comparison. The report also outlines the many qualitative factors involved in selecting the type of distribution system and through an extensive consideration of aesthetic factors indicates the potential of hybrid approaches which avoid problems of overhead systems at a fraction of the cost of fully underground construction. The concepts are illustrated by case studies involving rural, suburban and urban applications, which involve both new development and reconstruction.

Appendixes contain cost and reliability data as well as background information and analytical details. Three case studies are presented which demonstrate the analytical selection process for a rural distribution system, a new suburban residential subdivision and the redevelopment of an urban area with a mixed residential and commercial load.

Extensive failure rate data is presented in Appendix A. Surveys were sent to Alberta Power Limited, Edmonton Power, Newfoundland Power, TransAlta Utilities, Toronto Hydro, and Winnipeg Hydro concerning equipment failure rates. Results of these surveys are tabulated in Tables A2.1 through A2.2. Table A2.1 deals with primary cable. Component types are rural 1 phase urban 1 phase, rural 3 phase, and urban 3 phase. Data recorded include: Voltage Class, insulation type, conductor type, jacket material, typical age, type of installation, installation technique, expected useful life, length in service, failures per year, failure rate, service restoration time, repair time, and maintenance cost per event. Table A2.2 deals with separable connectors. Component types are rural 1 phase urban 1 phase, rural 3 phase, and urban 3 phase. Data recorded include: Voltage Class, contin. current, elbow duty, age, number in service, failures per year, failure rate, service restoration time, repair time, and maintenance cost per event. Table A2.3 deals with underground transformers. Component types are rural residential, urban residential, commercial, and industrial. Data recorded include: Voltage Class, transformer phases, transformer installation, transformer insulation, typical transformer size, protection combination, useful life, number in service, failures per year, failure rate, service restoration time, repair time, and maintenance cost per event. Table A2.5 deals with overhead primary line installations. Component types are rural 1 phase urban 1 phase, rural 3 phase, and urban 3 phase. Data recorded include: Voltage Class, conductor type, age, typical framing, typical pole height, typical span length, Typical system configuration, useful life, length in service, failures per year, failure rate, service restoration time, repair time, and maintenance cost per event. Table A2.6 deals with overhead transformers. Component types are rural residential, urban residential, commercial, and industrial. Data recorded include: Voltage Class, transformer phases, transformer insulation, typical transformer size, protection combination, useful life, number in service, failures per year, failure rate, service restoration time, repair time, and maintenance cost per event. Table A.3.1 lists published data collected from other sources. Components covered in the table are: Cable at 1 yr, 1 ph-XLPE; Cable at 10 yr, 1 ph-XLPE; Cable at 15 yr, 1 ph-XLPE; Cable, 1 ph-KWWPE; 3-phase cable, 3ph-PILC; 1-phase cable, 1 ph-XLPE; Cable, 3ph-PILC; Cable at 0.76 cover, 1 ph-XLPE; Cable at 0.94 cover, lph-XLPE; Cable at 1.12 cover, lph-XLPE; Cable, lph-XLPE; -dig ins, 1 ph-XLPE; -other, 1 ph-XLPE; Typical open wire, 3ph; 12 kV primary, 3ph; Separable connector; Elbows; Splices; Switch; 3-phase switch; Circuit breaker; 12 kV recloser; Distribution Tx, lph Padmt; Distribution Tx, 3ph Padmt; Distribution Tx, 1 ph Sub; Distribution Tx, 1 ph/O/H; Distribution Tx, 1 ph/Q/H; Distribution Tx, 1 ph/O/H; 7.2 kVTx; Fuse; Lightning arrestor; Secondary. Information provided on each component includes Failure Rate, Repair Rate, Maintenance Outage Rate, Maintenance Downtime, Source, and Year(s) of Statistics.

The cover page, abstract, executive summary, table of contents, Table A3.1, and the references for Table A3.1 are found in the reliability reference library. The entire report can be found in the EPRI library."

Search terms and ID: Multiple, Financial, Data, Report, 269

CEA, 1999

CEA

"1998 Annual service continuity report on distribution system performance in Canadian electrical utilities composite version," 1999, May, Canadian Electricity Association, Montreal, Quebec

This is a statistical report covering 32 Canadian utilities and 7 International companies for the year 1998 with comparisons to 1997 and to the 1994-1998 5-year averages. The data reported are mainly indices of reliability from a customer perspective, for example, SAIFI, SAIFI (momentary), SAIDI, and CAIDI. Also reported are the following indicators of causes: unknown/other, scheduled outage, loss of supply, tree contacts, lightning, defective equipment, adverse weather, adverse environment, human element, and foreign interference. The bulk of the materials reported are averages for Canada. Several charts do show the data on a utility-by-utility basis, but without the individual utilities being identified.

No data is reported on specific equipment.

Search terms and ID: System, Data, Causes, Report, 224

CEA, 1998

CEA

"Forced outage performance of transmission equipment," 1998, July, Canadian Electricity Association, Montreal, Quebec

This report contains extensive data on transmission outages from the CEA's Equipment Reliability Information System (ERIS). Detailed data on lines, transformer banks, circuit breakers, cables, synchronous and static compensators, shunt reactors, shunt capacitor, and series capacitors, as well as their subcomponents is given. Failure rates and duration information is given by outage type, cause, and voltage level. The data is compiled from 11 participating Canadian utilities.

The report is issued every 5 years. Transmission is defined as above 110 kV. No data is provided on an age basis. An up to 109 kV classification is provided for shunt reactor banks, shunt capacitor banks, and series capacitor banks.

Search terms and ID: Multiple, Data, Report, 221

Chang, 1979

Chang, N.E.; Gilmer, D.L.; Mciver,J.C.

"Cost-Reliability Evaluation of Commercial and Industrial Underground Distribution System Design, Conference Paper Discussion for," IEEE Power engineering society discussions and closures of abstracted papers from the winter meeting, 1979, February 4-9, IEEE, New York, New York

This paper contains questions and replies regarding a paper that we do not have. Without the paper they are of little or no value.

Search terms and ID: System, Other, Proceedings, 254

Chapel, 2000(1)

Chapel, Steve; Morris, P.E. ; Downs, C.; Feinstein, C.D.

"Customer Needs for Electric Power Reliability and Power Quality: EPRI White Paper," 1000428, 2000, November, EPRI, Palo Alto, California

The report reviews the current state of knowledge about customers' needs for electric power reliability. It includes descriptions of methodologies for assessing outage costs, quantitative and qualitative results of studies, description of a framework for estimating the value of reliability, a comparison with traditional approaches to measuring reliability, and a bibliography.

Search terms and ID: Non-specific, Financial, Report, 1

Chapel, 2000(2)

Chapel, S.; Morris, P.; Feinstein, C.

"Managing Aging Distribution System Assets," 1000422, 2000, December, EPRI, Palo Alto, California

Describes research done to identify and develop methods for making decisions about aging assets in electric distribution systems. The problem of aging assets has become more important because of the increasing emphasis on reliability and customer services. Distribution assets, such as substation transformers, feeders, poles, wires, breakers and other equipment are subject to failure. The probability of failure is dependent upon at least four factors: loading, age, maintenance, and external conditions. The decisions that distribution system managers must make include when to replace an asset when to repair or overhaul an asset, when to maintain and asset, and when to do nothing. The optimal decision depends on the four factors listed above combined with the costs of various alternatives. The methods being developed seek and optimal (least-cost) policy for maintenance and replacement of electric distribution assets.

The report begins with a discussion of methodology, an overview of the aging process, data, and the currently implemented tools. In the next section, a brief literature review is review is presented. The last two sections review analytic procedures and propose an analytic procedure."

Distribution assets include: substation transformers, feeders, poles, wires, breakers, and other equipment. Probability of failure is dependent upon at least four factors: Loading, age, maintenance, and external conditions Actions are summarized as replacement, repair, maintenance, and do nothing. Methods seek a least cost alternative

Search terms and ID: Non-specific, Financial, Technical, Report, 2

Chapel, 2000(3)

Chapel, S.; Morris, P.A. ; Cedolin, R.; Feinstein, C.D.

"Reliability of Electric Utility Distribution Systems: EPRI White Paper," 1000424, 2000, October, EPRI, Palo Alto, California

"The report describes what is known with respect to the reliability of electric power distribution systems. It describes the state of knowledge, tools and practices for distribution system reliability. The report is based on an extensive literature survey, which investigated papers, reports, books and electronic media. The report discusses definitions of reliability; utility planning practices; the role of regulators; utility power quality approaches; and existing methods for reliability analysis. The main conclusion of the report is that, although the theory of reliability of systems is well developed, the application of analytical techniques to distribution systems planning is limited. There is no single, generally available, methodology that distribution planners can use to answer the questions associated with reliability-based planning.

The report provides: an excellent summary of the state-of-the-art in reliability, suggestions for new approaches, and an extensive literature review."

Search terms and ID: System, Financial, Technical, Report, 48

Chen, 1995

Chen, Rong-Liang; Allen, Kim ; Billinton, R.

"Value-Based Distribution Reliability Assessment and Planning," IEEE Transactions on Power Delivery, 1995, 22-Jan, 10, 1, IEEE

This paper discusses VBDRA (value-based distribution reliability assessment) and its 1992 application at Scarborough Public Utilities Commission (SPUC) to assess feeder projects. VBDRA combines distribution reliability indices with customer interruption costs at load points. The reliability assessment model follows that in the Guide to Value Based Reliability Planning, also written by Billinton. Outage exposure is assessed both by the load point and component failure techniques. The analytic results from these two techniques for the total customer interruption costs are proven to be algebraically equivalent. However, the load point technique is found to be much faster computationally. The data requirements for an assessment are outlined. Feeder level reliability indices are defined and calculated and combined with customer interruption costs to calculate relative benefits of a number of competing capital-investment feeder projects at SPUC. SPUC's own historical fault data, and that from North York Hydro, and customer interruption costs from previous work are used. The resulting project prioritization was used by SPUC in its capital budget planning, and a reliability assessment was repeated a couple of years later showing an improvement in overall customer interruption costs.

Customer interruptions are a function of both equipment failure rates and failure durations. VBDRA application as a spreadsheet macro is demonstrated."

Table 1 lists equipment failure rate and durations (columns) for cable, elbow, fuse, fault interrupter, overhead line, splice, switch, and transformer.

References for the data are:

W.F. Horton, S. Goldberg and R.A. Hartwell, "A Cost/Benefit Analysis in Feeder Reliability Studies", IEEE Transactions on Power Delivery, Vol.4, No.1, 1989, pp. 446-452.

S.R. Gilligan, "A Method for Estimating the Reliability of Distribution Circuits", IEEE Transactions on Power Delivery, Vol.7, No.2, 1992, pp.694-698.

W.F. Horton, S. Goldberg and C.A. Volkman, "The failure Rates of Overhead Distribution System Components", Proceedings of the Transmission and Distribution Conference, IEEE, Dallas, Sept.1991, pp. 713-717 15.

W.F. Horton, S. Goldberg and C.A. Volkman, "Determination of Failure Rates of Underground Distribution System Components from Historical Data", Proceedings of the Transmission And Distribution Conference, IEEE, Dallas, Sept.1991, pp.718-723.

North York Hydro, "1991-1992 Underground Rebuilds Plan", November 20, 1989.

Shortest failure durations have the highest customer interruption costs per hour because momentary power losses have the highest costs per hour."

Search terms and ID: Multiple, Financial, Data, Proceedings, 44

Chowdhury, 2000

Chowdhury, A.A.; Koval, D.O.

"Current practices and customer value-based distribution system reliability planning," Conference record of the 2000 IEEE Industry Applications Conference, 2000, 2, IEEE

Utilities are increasingly recognizing that the level of supply reliability planned and designed into a system has to evolve away from levels determined basically on a technical framework using deterministic criteria, and towards a balance between minimizing costs and achieving a sustainable level of customer complaints. Assessment of the cost of maintaining a certain level of supply reliability or making incremental changes therein must include not only the utility's cost of providing such reliability and the potential revenue losses during outages, but also the interruption costs incurred by the affected customers during utility power outages. Such a cost-benefit analysis constitutes the focal point of the value-based reliability planning. Value-based reliability planning provides a rational and consistent framework for answering the fundamental economic question of how much reliability is adequate from the customer perspective and where a utility should spend its reliability dollars to optimize efficiency an satisfy customers' electricity requirements at the lowest cost. Explicit considerations of these customer interruption costs in developing supply reliability targets and in evaluating alternate proposals for network upgrade, maintenance, and system design must, therefore, be included in system planning and design process. The paper provides a brief overview of current deterministic planning practices in utility distribution system planning, and introduces a probabilistic customer value-based approach to alternate feed requirements planning for overhead distribution networks.

Contains no useful data. A fairly general discussion of value-based planning with a very simple example. May be of interest as an alternative presentation of the topic.

Search terms and ID: Non-specific, Financial, Proceedings, 232

Choy, 1996

Choy, Siang-Ying; English, John R. ; Landers, T.L.; Yan, L.

"Collective approach for modeling complex system failures,"1996 proceedings annual reliability and maintainability symposium, 1996, 282-286

This paper defines the functional requirements of a DSS necessary to serve as a working tool in assisting the reliability engineer in equipment repair/replacement management of material handling equipment.

Focuses on modeling not data

Search terms and ID: System, Technical, Proceedings, 60

Collard, 1980

Collard, Steve; Paracos, Edward; Kressner, A.

"Root Cause Failure Analysis In Electrical Transmission and Distribution Equipment,"1980 Proceedings Annual Reliability and Maintainability Symposium, 1980, January 22, IEEE

"The paper discusses root-cause failure analysis on electric power equipment. This analysis was motivated by lack of failure analysis activity beyond the warranty period of electric equipment, and the reluctance of the manufacturers to get involved in such activity. The paper defines failure analysis as the performance of a detailed study to establish the failure mode, mechanism and cause-and-effect of each experienced failure. The conceptual framework for root-cause failure analysis is based on an understanding of the nature of the equipment failure: (1) every failure has a cause; (2) unless the cause is corrected the failure will occur again; (3) as stresses on a component increases so will the failure probability; (4) eliminating the cause as the only way to avoid future failures; (5) thorough examination and analysis of failed part to determine the cause of failure; and (6) if a specific failure occurs from a natural cause it can be induced in the laboratory.

For each analysis the paper provides a summary of the type of equipment, findings, cause of failure and recommendations. The analysis is performed on network protector motors failures, high voltage circuit breaker O-ring seal failures, and network primary cable and joint failures. The paper concludes by pointing that root-cause failure analysis is now an established function at Con Edison. The paper is interesting from the empirical point of view, but has no modeling value for us.

Article supports failure analysis as a means to improve reliability of equipment and to increase availability. Failure analysis also allows suppliers to improve equipment design."

Low-bid procurement has caused some suppliers to abandon failure analysis and to design equipment to survive the warranty period.

Search terms and ID: Multiple, Causes, Journal Article, 40

Commonwealth Edison, 1998

Commonwealth Edison

"Commonwealth Edison Co. 1998 Report on Reliability to the Illinois Commerce Commission," 1998, iii-99, Illinois

Report submitted by the Commonwealth Edison Company (ComEd) to the Illinois Commerce Commission regarding transmission reliability rules. Report summarizes ComEd outage causes for 1998.

Table 3 lists the number of planned and unplanned interruptions for the system. Table 4 lists the number of planned and unplanned interruptions in the Chicago area. Table 5 lists the number of planned and unplanned interruptions in the Northeast area. Table 6 lists the number of planned and unplanned interruptions in the Southern area. Table 7 lists the number of planned and unplanned interruptions in the Northwest area. Table 8 provides detailed data regarding controllable interruptions for Chicago, the Northeast, Southern, Northwest, and the system. For Tables 4 through 8, the total number of interruptions is provided, as well as the average interruption duration. Planned interruptions include those scheduled for construction, maintenance, or repair. Unplanned interruptions are caused by other utilities or suppliers, ComEd/Contractor personnel errors, customers, the public, weather, animals, trees, overheated equipment, underground equipment failures, international, transmission and substation equipment related, or other. Figures 4 through 10 display the distribution of lightning arresters, feet of buried cable, feet of overhead distribution conductors (aluminum and copper), number of distribution poles, number of crossarms, number of meters, and capacity of distribution transformers versus their respective ages. Table 9 presents a summary of the number of interruptions for the Chicago, Northeast, Southern and Northwest operating areas. Table 10 provides transmission expenditures and Table 11 distribution expenditures in 1998 for the ComEd system. Tables 12 and 13 present customer satisfaction data. Table 14 lists customer reliability complaints regarding sustained interruptions, momentary interruptions, low voltage and high voltage complaints for Chicago, Northeast, Southern, Northwest and the system as a whole. Table 15 presents CAIDI, CAIFI and SAIFI data for Chicago, Northeast, Southern, Northwest and the system as a whole. Tahles 16 through 19 provide a list of the worst performing circuits in 1998 or the Chicago, Northeast, Southern and Northwest areas in terms of CAIDI, CAIFI and SAIFI. Following Tables 16 through 19 is a detailed breakdown of the worst 1% of Chicago operating area circuits as measured by the CAIDI index. The detailed information includes the circuit identification, interruption date, number of customers affected, duration, cause, date of last inspection, date of last tree trimming and a description of the work to repair the circuit, as well as the cost of the repair. Such data is provided for 19 circuits. Next, the worst 1% of Chicago operating area circuits as measured by the CAIFI/SAIFI indices is presented. Each of 19 circuits is documented with each interruption date, number of customers affected, the duration and cause. The date of last inspection, date of last tree trimming, and a work description/cost of work are also chronicled. Similar data is presented for the Northeast operating area (17 CAIDI and CAIFI/SAIFI data entries), Southern operating area (8 CAIDI and CAIFI/SAIFI data entries) and the Northwest operating area (7 CAIDI and CAIFI/SAIFI data entries). Tahle 20 provides the peak demand and projected load (in Megawatts) for each of the four operating areas (and the corresponding total) for 1998 and projected numbers for 1999, 2000 and 2001. Table 21 presents the peak loading on each distribution transformer at or above 90% for the Chicago, Northeast, Southern and Northwest operating areas. The transformer ID, normal rating, emergency rating, 1998 peak loading (all in MVA), percent of normal rating and percent of emergency rating are displayed. Table 22 presents the distribution transformer loading corrective actions for transformers in each of the four operating areas. Table 23 presents the peak loading on each transmission transformer at or above 90%. Specific data include the ComEd operating area, station, transformer ID, normal rating (in MVA), emergency rating (in MVA), 1998 peak loading (in MVA), percent of normal rating and percent of emergency rating.

Search terms and ID: System, Data, Causes, Report, 90

Connor, 1966

Connor, R.A.W.; Parkins, R.A.

"Operational Statistics in the Management of Large Distribution Systems," Proceedings of the Institution of Electrical Engineers, 1966, November, 113, 11, 1823-1834, IEE, London, UK

In order to manage a large distribution system in the best manner, it is considered necessary to have comprehensive, accurate and up-to-date records of the number and types of equipment items in service, together with properly analyzed records of their performance.

With the advent of nationalization of the supply industry in 1948, and the formation of a small number of large undertakings, it hecame possible to study the performance of large networks in a manner not previously possible. The paper gives details of the way in which the necessary data are collected, analyzed and used in one Area Board. Details are given of some of the conclusions reached to date of some other problems, which are being studied, and some observations are made on reliability and security of supplies.

Although some problems do not lend themselves to analytical treatment of the type described, many do, and it is contended that a great deal of valuable information on design, construction, operation and maintenance of networks can be obtained from the analysis of properly compiled data."

The paper was written in 1965 and generally covers data during the preceding 14 years (1951-1965). Covers networks with nominal system voltages of 2-33kV. No data is provided relating failure rates to aging. However, considerable data is provided on failure rates. Table 1 provides data on overhead line faults. Columns indicate the system voltage and method of earthing, 2 to 33 kV in six intervals with earthing designated as s.r.o. or a.s.c.. Rows represent failure mechanisms and total failures. The failure mechanisms include: lightning, abnormal weather conditions, growing trees, windborne materials, human agency, birds, conductor failure, joint or clamp failure, jumpers, binders, insulation failure, failure of support, failure of pole-mounted switch on fuse gear, miscellaneous, and unknown. Table 2 provides data on underground cable failures. Columns indicate the system voltage and method of earthing, 2 to 33 kV in six intervals with earthing designated as s.r.o. or a.s.c.. Rows represent failure mechanisms and total failures. The failure mechanisms include: human agency, mechanical damage to sheath, corrosion, insulation failure, pole-box failure, joint failure, ground subsidence, miscellaneous. Table 3 provides data on failures of underground cable terminations and joints. Columns are provided for 11kV and 33kV. Rows designate cable joint failures per 100 miles per annum, cable joint failures per 100 joints per annum, cable terminators failures per 100 miles per annum, cable terminators failures per 100 joints per annum, pole boxes failures per 100 miles per annum, pole boxes failures per 100 joints per annum. Table 4 presents transformer data. Columns indicate the system voltage and method of earthing, 2 to 33 kV in six intervals with earthing designated as s.r.o. or a.s.c.. Rows represent failure mechanisms and total failures. The failure mechanisms include: bushing failure, winding failure, oil quality, overload, tap-change mechanism, miscellaneous. Table 5 presents switchgear failure rates per 100 switchgear units. Rows represent failure mechanisms and total failures. The failure mechanisms include: circuit-breaker failures, tripping or closing mechanisms, A.R. tripping or closing mechanism, current transformers, voltage transformers, other failure of outdoor switchgear, other failures of indoor switchgear, small wiring and auxiliary switches, failure of metal clad fuse switch, failure of metal clad oil-immersed isolator or switch, failure of air-break isolator, miscellaneous. Table 6 presents protective-gear fault causes. Columns are faults per 100 switchgear units per annum and % of total number of faults. Rows are causes. The causes include: relays and components, Incorrect settings, Failure of trip supply, A.C. trip circuit and t.l. fuses, Wiring defects, Pilot cables, Incorrect connections, Incorrect circuit diagram, Interference with secondary wiring, Testing errors, Vibration or mechanical shock, Incorrect characteristic, Unknown at time of original report, All causes

Search terms and ID: Multiple, Data, Causes, Journal, 260

Contaxis, 1989

Contaxis, G.C.; Kavatza, S.D. ; Vournas, C.D.

"Interactive Package for Risk Evaluation and Maintenance Scheduling," IEEE Transactions on Power Systems, 1989, May, 4, 2

This paper describes an interactive computer package for evaluating the risk level of a power system and for scheduling the preventive maintenance of the system's generating units. The risk is calculated via the loss of load probability (LOLP). The paper reviews solutions for LOLP calculation based on convolution of simple bimodal probability distributions that each describe the capacity outage probability associated with (binary) variable of capacity (0 or full capacity) for each generator (the convolution over these bimodal distributions gives the total probability distribution associated with system capacity). The objective function of the maintenance scheduling is minimization of the annual system risk while all the physical and technical constraints imposed by the system and the planning practices are met. The paper considers optimization of this objective function (subject to constraints) with respect to maintenance scheduling of the generators. Pointing out the difficulties and state of the art as related to calculation of LOLP and the integer nature of maintenance scheduling optimization, the paper introduces two additional approximate solutions (based on effective reserve and levelized risk levels) for the posed problem. A demonstrative case study has been considered.

"

LOLP helps calculate the capacity outage probability table (COPT). LOLP can be determined several different ways.

Search terms and ID: Generators, Maintenance, Technical, Journal Article, 29

Dalabeih, 1995

Dalaheih, D.M.; Jebril, Y.A.

"Determination of Data for Reliability Analysis of a Transmission System," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 19-23, IEE, Norwich, UK

Statistical analysis of reliability data from 1989 to 1993 for the 132 kV Jordanian Transmission System.

Table 2 provides data for outage types, duration and number of data points for 132 kV transmission line outages, 341 data points. Table 3 provides component forced outage rates for 132/ kV transformers, 132 kV circuit breakers and 132 kV busbars (1505 T-unit year of exposure). The table displays outages/ unit year, number of outages observed, T-unit year of exposure. Table 4 lists component scheduled outage rates132/ kV transformers, 132 kV circuit breakers and 132 kV busbars (655 T-unit year of exposure), Table 5 lists component forced outage duration for 132/ kV transformers, 132 kV circuit breakers and 132 kV busbars (655 data points), Table 6 lists component scheduled outage duration for 132/ kV transformers, 132 kV circuit breakers and 132 kV busbars (476 data points),

Search terms and ID: Multiple, Data, Proceedings, 65

Darveniza, 1996

Darveniza, M.; Mercer, D.R.; Watson, R.M.

"Assessment of tbe reliability of in-service gapped silicon-carbide distribution surge arresters, An," IEEE Transactions on Power Delivery, 1996, October, 11, 4, 1789-97, IEEE

Although electricity authorities no longer purchase gapped silicon carbide arresters, they still form the majority of the very large number of distribution arresters in service in Australia and many other countries. Most of the arresters of this type are now over ten years old and many are much older. So tbe question must be asked-what is to be done with this ageing and outdated class of arresters? Extensive Australian studies in the 1960s had revealed that internal degradation resulting from inadequate seals was the predominant cause of failure of gapped silicon carbide arresters. This paper describes the results of a recent investigation. Electrical testing showed that after about 10 years of service, there is a marked upturn in the number of arresters with unsatisfactory insulation resistance, and after about 13 years of service, a marked upturn in the number of arresters with reduced power frequency spark over level. Inspection of the internal components of dismantled arresters confirmed that the likelihood of significant degradation increased markedly with years of service, and was evident in almost 75% of arresters with 13 years or more of service. The authors therefore recommend that modern metal oxide arresters progressively replace all gapped silicon carbide arresters with 13 or more years of service.

The data is somewhat hard to interpret. It concerns the performance of surge arrestors in response to laboratory testing rather than field performance. The sample was 365 surge arrestors from eight Australian utilities. Voltage ratings ranged from 9kV to 24kV, about 80% had a current rating of 5kA while the remainder were rated at 10kA. The arrestors were subject to 5 tests. Figure 1 indicates how many of the arrestors passed or failed the tests. All possible combinations of pass-fail are reported. Table 2 presents failure rates by age. A discussion note points out the unreliability of several of the tests that were conducted.

Search terms and ID: Other, Data, Causes, Journal Article, 234

Dedman, 1990

Dedman, J.C.; Bowles, H.L.

"Survey of URD cable installed on rural electric systems and failures of that cable, A,"1990 Rural Electric Power Conference, 1990, D2-1 -- D2-7, IEEE, New York, NY

Several surveys have been conducted with the purpose of determining the history of failure of underground power cables. Typically, these surveys are used to compare data related to cables of various types or installation conditions. The Rural Electrification Administration (REA) has determined that most of the studies have not supplied valid or meaningful information, because neither the vintage of the cables nor their age at failure was considered. In 1988 and 1989, REA conducted a survey that supplied results that are both valid and meaningful. Analysis of the data reported by over 100 rural electrical cooperatives revealed trends related to several variables, such as insulation material and thickness, jacketing, conductor type, and installation methods. The cumulative total of failures, to date, of the cable installed in each year since 1970 was calculated and broken down according to the same variables. The results of the survey are discussed, and recommendations concerning ways that electric utilities can effectively use the results in considering replacement of aged cables are presented.

This study was initiated in 1998. The primary goal of the study was to associate cable failure to the vintage of the cable and its age at failure. Reports from 105 systems were collected. Many cable and installation characteristics were recorded in the survey. Data relevant to year of installation, cable jacketing, insulation material, insulation thickness, burial method, and stranding type are reported in this summary.

Figure 1 shows year versus total cable installed. Figure 2 shows year installed versus cumulative failures per 100 miles. Figure 3 shows % cable installed bare, jacketed or unknown versus year. Figure 4 shows cumulative failure per 100 miles versus year installed for both bare and jacketed cable. Figure 5 shows % cable using different insulation materials. Figure 6 shows cumulative failure per 100 miles versus year installed for each insulation material. Figure 7 shows % cable installed with different insulation thickness. Figure 8 shows cumulative failure per 100 miles versus year installed for each insulation thickness. Figure 9 shows % cable installed with different cable burial methods. Figure 10 shows cumulative failure per 100 miles versus year installed for each burial method. Figure 11 shows % cable installed with different conductor stranding types. Figure 12 shows cumulative failure per 100 miles versus year installed for each stranding type."

Search terms and ID: Cables, Data, Causes, Proceedings, 236

Degen, 1995

Degen, Wolfgang

"Design for Reliability Methodology and Cost Benefits in Design and Manufacture," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 61-65, IEE, Norwich, UK

Paper discusses the importance of quality and reliability in switchgear and the improvements over time in reliability.

Paper does not specifically discuss reliability and replacement, but it does provide some useful data. The sample size and timeframe for the data are not specified. Table 1 provides data for failure rates per 100-cb years for CIGRE and Siemens switches. The data further provides the percentage of failures among major causes. A useful reference mentioned is the Second International Enquiry into Reliability of High Voltage Circuit Breakers (CIGRE 1988-1991).

Search terms and ID: Switches, Data, Causes, Proceedings, 67

DeLima, 1998

DeLima, Fabio

"Discussion of "transmission equipment reliability data from Canadian Electrical Association","
IEEE transactions on industry applications, 1998, March, 34, 2, 415, IEEE

Comments on the meaning and usefulness of the data presented in an earlier paper.

"Provides two useful references:

D.O. Koval, IEEE Trans. Ind. Applications, vol 32, pp. 1431-1439, Nov/Dec 1996

C.R. Heising, ""Worldwide reliability survey of high-voltage circuit breakers, ""IEEE Ind Applications Mag., vol 2, pp65-66, May/June 1996

"

Search terms and ID: Multiple, Other, Journal Article, 54

Dixon, 1983

Dixon, G.F.L.; Hammersley, H.

"Reliability and Its Cost on Distribution Systems," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 81-84, IEE, London

Paper discusses reliability of British distribution networks and provides data regarding reliability costs, investment strategies and aids in decisions for drastic changes.

This may serve as a good background for developing a model for the cost of failures, but doesn't address likelihood of component failures explicitly. Systems are discussed, but no components are specifically discussed.

Search terms and ID: System, Financial, Design, Proceedings, 14

Dougherty, 2000

Dougherty, Jeff G.; Stebbins, Wayne L.

"Power quality: a utility and industry perspective," Energy User News, 2000, March, 25, 3, 12

Provides a long list of quality problems and discusses the causes and proposes some solutions. Problems noted include: sags and swells, long duration variations, impulsive transients, oscillatory transients, harmonic distortion, voltage fluctuations, and noise.

Search terms and ID: Multiple, Causes, Design, Journal Article, 204

Douglas, 1995

Douglas, J.A.K.; Randles, N.J.L.; Magee, D.; Bailie, H.D.

"Ranking of Design Criteria to Improve Rural Network Performance," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 145-150, IEE, Norwich, UK

Model based on probabilistic circuit modeling is used to evaluate different design criteria and the corresponding technical benefits. Improvements are aimed at security and availability indices.

Data synthesized by a technical model. Table 1 displays data predicted by the model and actual performance in terms of customer hours lost, CML, customers affected, and interruptions per 100 customers, faults and faults per 100 km. States that the UK average is 12.5 faults per 100 km.

Search terms and ID: System, Design, Model, Proceedings, 72

East Midland Electricity, 2000

East Midland Electricity

"Quality of Supply Report (1999/2000)," 2000, East Midland Electricity

Yearly supply performance report. Contains descriptions of mechanical and natural failures by location.

Data is divided by region. 11 kV unplanned minutes lost by cause data is presented for Coventry and Warwickshire, Derbyshire, Leicestershire, Lincolnshire, North Hamptonshire and Nottinghamshire. Condition Report 9 (page 26) displays supply interruption data by location for low voltage cutouts and mains and high voltage overhead and underground lines. Pages 28 to 30 display the performance of 11 kV lines by location.

Search terms and ID: System, Data, Report, 126

EBASCO Services Inc., 1987

EBASCO Services Inc.

"Electric Distribution Systems Engineering Handbook," 1987, McGraw Hill Publication Co., New York, New York

The goal of this handbook is to survey the entire field of distribution system engineering. It is a large text and provides detail on many engineering tasks; however, it provides minimal depth on advanced issues. The topics covered include: planning and design criteria; economics standard specifications, codes, and regulations; radial primary systems; and utilization equipment and load characteristics. System reliability is discussed in Chapter 1, Section E161.

"Only the cover page, contents, and reliability data from this book is found in the reliability library. The book itself is available in the EPRI library.

The book provides very limited reliability data. One table is presented in the context of an example of reliability calculations. Table 2 on page 30 of Chapter 1, Section 161 presents the reliability data for distribution components. Data (columns) include survey period, failures per year, expected repair time, and maintenance outages per year, maintenance outage time. Components include (columns) 69/12kV transformer, 69kV lines, 69&12kV breakers, 69&12kV buses, 12kV recloser, 12kV tie feeder, 12kV primary, and 7.2kV transformer."

Search terms and ID: System, Technical, Financial, Book, 261

Edwin, 1983(1)

Edwin, K.W.; Dib, R. ; Niehage, U.

"Reliability Investigations for 110-kV Subtransmission Networks," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 73-77, IEE, London, United Kingdom

Overhead lines are subjected to atmospheric influences, and are thus frequently interrupted by one- or multi-phase faults. A method used to calculate reliability of subtransmission networks is presented and applied. It was determined that most simultaneous outages were due mainly in common-cause faults in double circuit transmission lines and simultaneous ground faults and the protection system failing to operate.

The data source is not specified beyond two German utilities. Neither a date for the data or sample size is provided. Table lists for Resonant neutral earthing and for low impedance neutral earthing and power transmission line, power transformer, busbar, busbar disconnector, and circuit breaker switch bay (rows) the following data: rate of independent forced outages, rate of independent scheduled outages, rate of primary outages due to simultaneous ground faults, common-cause outage rate of double circuit transmission line, conditional probability of sequential outage due to simultaneous ground faults, conditional probability of sequential outages due to protection system failing to operate, mean duration of forced outages, excluding outages due to simultaneous ground faults, mean duration of forced outages due to simultaneous ground faults, mean duration of scheduled outages, mean duration for common-cause outages of double circuit transmission lines, mean duration of switching actions (columns). The results of the failure affect the analysis for the following components of a subtransmission network: power transmission lines, power transformer, busbar, busbar disconnector, and circuit breaker switch bay.

Search terms and ID: Multiple, Technical, Data, Journal Article, 4

Edwin, 1983(1)

Edwin, K.W.; Nachtkamp, J. ; Siemes, B.

"Statistical Determination of the Availability of Important Components in the Electrical Power Supply," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September 19-21, 225, 115-118, IEE, London, United Kingdom

Confidence levels in probabilistic reliability models depend on the knowledge of component reliability. Data on several 110 kV grids is presented, but due to high reliability levels, it is difficult to form sufficient sample sizes.

" Data regarding reliability characteristics of overhead lines are presented in Table 4. The data was collected for 412 line/operation-years i.e. 9898km/operation-years from several inductively earthed 110 kV-grids, presumably in Germany. Data for these lines include: average forced outage frequency, average forced outage duration, % unplanned unavailability, confidence interval on % unplanned unavailability, % scheduled uptime, and % total expected availability.

The author notes," "The average frequency of about one failure per line in two years is so small, that the data of all observed lines had to be evaluated together."" Also," "Due to the high reliability level it is difficult to form samples with a sufficient size.""

Outage behavior is best approximated with a Weibull distribution. Reliahle maintenance schedules can only be created if preventative maintenance provides for components subjected to heavy mechanical wear. A graph with repair-density versus repair duration data for turbines, boilers, and generators for a 150 MW coal unit are also provided."

Search terms and ID: Cables, Data, Technical, Proceedings, 16

EPRI, 1990

EPRI

"Cost-Benefit Analysis of Power System Reliability: Determination of Interruption Costs," EL-6791, 1990, April, 1, 6-13 - 6-29, EPRI

European, Canadian and Brazilian reliability standards for generation are reviewed. At the transmission level, describes steps in planning and steps in quantitative reliability analysis. For the distribution system, lists sources of customer interruption and reviews reliability planning indices measuring customer reliability, feeders/circuits reliability, and system reliability. Voltage and current, fault current levels, and protective devices influence distribution system reliability. Investment decisions about system reliability regarding protection, system upgrades, facility design, maintenance, automation, etc., are described.

Table of system-wide outage costs for different countries is included, as well as a table of 1985 interruption statistics for U.S. facilities.

Search terms and ID: System, Financial, Technical, Report, 45

Farag, 1999

Farag, A.S.; Wang, C.; Cheng, T.C.; Zheng, G.; Du, Y.; Hu, L.

"Failure analysis of composite dielectric of power capacitors used in distribution systems," Electric machines and power systems, 1999, March, 27, 3, 279-294, Taylor & Francis

This paper describes the study of the reliability of capacitor units installed and operated in distribution systems during the period 1980 through 1990. Failures of capacitor units in distribution substations can be very costly to the supply of reliable power to consumers. To enhance utility reliability, failure analysis, and rates, failure origin and physical damage causes were performed for these capacitor units. Two approaches, statistical and physical, were utilized in this study. In the statistical area, failure modes, reliability levels and failure causes are analyzed. The physical study mainly deals with the mechanism of deterioration of the composite dielectric. This paper models the capacitor's failure mathematical mode and calculates their failure rate. The results of the study of 2912 capacitor banks including 8736 capacitors installed at 153 distribution substations showed that the failure mode of capacitor units may be represented by Weibull distribution and each capacitor manufacturer has a different failure rate. Analysis showed that partial discharge properties are a critical indicator for the capacitor failure mechanism. Useful conclusions are presented both for power system operators and manufacturers. The methodology used in this study also applies to other equipment in the distribution system such as oil switches, transformers, and insulators.

"2912 banks including 8736 capacitors installed at 153 substations in LADWP 4.8kV distribution system. The rated voltage is 2.77 kV to ground and each single-phase capacitor is 150kVar. Three capacitors are banked to form a 450-kVar bank. Data from the period 1980 through 1990 have been analyzed. 541 failures were analyzed. All data presented is broken out by the four manufacturers of the capacitors; however, the manufacturers are not identified.

Table 1 indicates the cause of failure: main insulation breakdown, oil leaking, or broken bushing.

Figure two is a histogram of life times for the failed capacitors.

Figure three plots Y=mX-A where: Y=ln ln{1/[1-F(t)]}, X = ln(t), and A =ln(t0). F(t) is the Weibull distribution function. F(t)= 1-exp[(-t^m)/t0].

Table 3 presents for each manufacturer the sample size, the total number of failed capacitors, the parameters m and t0, and F(t).

Table 4 presents the results of the Kolmogrov Smirnov test. All distributions were acceptable by this test at the 5% level.

Table 6 provides the sample size, total number of failed capacitors, the failure rate function, and the mean time to failure.

Table 7 presents failure rate function, H(t), values for different years and the failure rate average calculated in two different ways. The first is based on the failure rate function. The second assumes that distribution function of capacitor life is and exponential distribution and that therefore the failure rate is constant.

The authors conclude that manufacturing has a significant impact on failure rate, and that oil switches because of a propensity to restrike are a poor choice for capacitor control.

Essentially the same paper was presented at the 7th International symposium on High Voltage Engineering."

Search terms and ID: Capacitors, Data, Causes, Journal Article, 231

Ferguson, 1987

Ferguson, R.P.

"Factors affecting the replacement of old transformers," Revitalizing transmission and distribution systems, 1987, February 25-27, 273, 113-118, IEE, London, United Kingdom

Discusses the monitoring of transformers in detail. Monitoring activities and tests discussed include: inspection for external corrosion, insulation resistance by DC Megger, loss angle (tan delta) at 50 Hz, partial discharge, low voltage impulse tests, gas-in-oil analysis, reactance measurement, low voltage impulse tests,

Search terms and ID: Transformers, Monitoring, Maintenance, Proceedings, 203

Fletcher, 1995

Fletcher, P.L.; Degen, W.

"Summary of the Final Results and Conclusions of the Second International Enquiry on the Reliability of High Voltage Circuit-Breakers, A," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 24-30, IEE, Norwich, United Kingdom

Summary of circuit breaker reliability covering the period of January 1988 to December 1991. Data equivalent to 70708 circuit-breaker years from 132 utilities and 22 countries was included.

Table 1 provides the number of circuit-breaker-years included in the summary. The data is segregated by voltage, location (indoor/outdoor), and metal versus non-metal enclosed. Table 2 provides data regarding major and minor failures segregated by voltage. Data are per 100 circuit breaker years. There are two age classes Placed in service 1/1/78 to 1/1/83 and after 1983. Table 3 provides data for subassemblies. Table 5 provides data on the type of failure. Table 7 provides data on the causes of failure.

Search terms and ID: Switches, Data, Causes, Proceedings, 66

Ford, 1972

Ford, D. V.

"British Electricity Boards National Fault and Interruption Reporting Scheme--Objectives, Development and Operating Experience, The," IEEE Power Engineering Society Winter Meeting, 1972, Jan 30-Feb 4, 2179-2188, IEEE

Paper describes a nation-wide interruption data collection procedure for the UK. Data collected can be statistically analyzed to assist in matching organizational requirements with system fault repair needs.

Main purpose of the paper is to explain the process for collecting data. Some data is provided. Ranges of annual failure rates for overhead lines, underground cables, transformers and switchgear are presented. Failure rates for EHV, HV and MV/LV systems are presented. Failure rates for EHV systems with duplicated circuits are presented, as well as the average duration of interruptions according to types of equipment failures. Tables for variation in annual fault totals by cause; variation in lightning-caused faults; annual relationship between system reliability and customer interruptions; and six-year trend in interruption statistics are presented.

Search terms and ID: System, Data, Journal Article, 117

Freeman, 1996

Freeman, J.M.

"Analyzing equipment failure rates," International journal of quality & reliability management, 1996, April, 13, 4, 39

Presents data and analysis of failures in 11kV/415V pole mounted transformers. Lists failures by age, shows cumulative failure rates, and mean cumulative hazard. Also, discusses estimation of Weibull and Gumbel parameters from the data.

"Sample includes 252598 pole mounted transformers (PMT's) in England and Wales. Failure data is from the Electricity Council's NAFIRS (National Fault and Interruption Reporting Scheme for the years 1984-1985. The following tables are included: Table I - age, estimated number in England and Wales, recorded failures, hazard rate; Table II - service life, reverse rank, hazard, cumulative hazard; Table III - age, mean cumulative hazard.

Our copy is from the Internet and does not contain the matbematical expressions or the figures."

Search terms and ID: Transformers, Data, Equations, Journal Article, 205

Gilbert, 1994

Gilbert, Dennis

"Cable derating and nonlinear load panelboards," EC&M Electrical Construction & Maintenance, 1994, February, Intertec

Suggests rules for derating cables when they are likely to experience harmonics. The paper does not relate economic factors to derating decisions. There is nothing methodologically interesting in the paper.

1993 NEC Note 1°C. requires cable derating due to harmonics

Search terms and ID: Cables, Design, Journal Article, 56

Gilligan, 1992

Gilligan, Sidney R.

"Method for Estimating the Reliability of Distribution Circuits, A," IEEE Transactions on Power Delivery, 1992, April, 7, 2, 694-698, IEEE

The article presents a method to predict the relative reliability performance of distribution circuits and circuit segments. The method calculates with a spreadsheet the expected relative indices of annual interruption time and customer hours of interruption by multiplying factors for exposed length, exposure (to weather factors such as trees as well as inherent failure), conductor type, sectionalizing devices used, and customers connected. The results must be normalized somehow to be compared to actual performance. Customer outage values of $1.30/kWh residential, $7.42/kWh commercial, and $9.27/kWh industrial are used to assess the cost effectiveness of reliability improvement projects suggested by the method. The author states that no historical data is required. The factors, though, are empirical, based on general experience with circuit operation. The method examines only the post-substation, pre-secondary-transformer circuits of distribution systems. An application of the method to about 100 distribution circuits is discussed. Although less accurate than a method using historical data in a more sophisticated model, this seems like a valuable, quick and simple method. An answer to the question of whether a more sophisticated reliability modeling method is worth the effort and cost over the method presented here must be addressed. The paper exposes the key point that a field assessment of equipment environment is important to a reliability analysis, dependent on the fact that a large proportion of distribution outages are caused by external events (e.g., weather related problems). The method assumes the multiplicative factors are all independent and that the indexes are linear functions of each factor (e.g., annual interruption time is linearly dependent on conductor length and on fault rate for the exposure and that the fault rate per length is not dependent on length). This is reasonable if the analysis is only addressing interruptions caused by external events, but possibly not for inherent equipment failure. The paper doesn't address restoration time. This article is referenced in a paper by Billinton "Value-based distribution reliability assessment and planning," 1/95, but the reliability prediction method isn't commented on there. It is just mentioned that failure rates are available in this paper.

Table II present fault rates for cable segments but the precise characteristics of the segments are unclear.

Search terms and ID: System, Technical, Financial, Journal Article, 63

Godfrey, 1996

Godfrey, R. M.; Billinton, R.

"Guide to Value-Based Distribution Reliability Planning, Volumes I and II," 273 D 887, 1996, January, Canadian Electricity Association, Montreal, Quebec

Value-based reliability planning is a subset of a broader planning methodology known as Integrated Value-Based Planning, which seeks to deliver maximum value to customers considering all of their needs. Value-based distribution reliability planning focuses on the value realized by customers through the combination of electricity tariffs and reliability of service. This guide presents data and analytical techniques that may be used to integrate all utility costs and customer outage costs in a comprehensive decision-making framework. The concepts are illustrated by example and by case studies involving project planning in an urban commercial area and a rural area. Appendixes include a comprehensive bibliography on distribution reliability analysis and reliability worth investigation, as well as a summary of published outage costs and an overview of utility opinion on value-based distribution reliability planning.

"This report contains perhaps the best data we have found in any published source. The data sources are varied and differ for individual pieces of equipment. To quote the report,""a summary of representative component reliability, which has been extracted and synthesized from a number of technical publications."" The data is contained in Tables 3.1-3 on pages 3-47 to 3-49. All tables specify the same data elements in columns. These are component, type/area, location (rural, urban, or any), year 1 failure rate, year 10 failure rate, terminal year failure rate, useful life, callout repair time, isolation repair time, repair/replace time, and source. Components covered are O/H line Xarm Rural, O/H Line Xarm Urban, O/H Line Armless Rural, O/H Line Armless Urban, O/H Line aerial Cable Urban, D.B. Cable XLPE Rural, D.B. Cable XLPE Urban, D.B. Cable TRXLPE-SF-PEEJ Rural, D.B. Cable TRXLPE-SF-PEEJ Urban, Cable in Duct XLPE Urban, Cable in Covered Duct XLPE Urban, Cable in C.E. Duct XLPE Urban, Cable in C.E. Duct TRXLPE-SF-PEEJ, Distribution Transformer Pole-mounted Rural, Distribution Transformer Pole-mounted Urban, Distribution Transformer Pad-mounted Rural, Distribution Transformer Pad-mounted Urban, Distribution Transformer Submersible Rural, Distribution Transformer Submersible Urban, Circuit Breaker, Reclosers, Fuse, Switch, Cable Elbow, Cable Splice, Lightning Arrestor.

The authors note, "This data appears reasonable and internally consistent, but it must be recognized that this data is based on selective reporting from utilities, in different jurisdictions, based on outage reporting systems which may define different events in different ways. As such, these figures must be used with some caution, as there is some risk of misinterpretation." The authors also note that a number of efforts were underway to collect superior data on a more consistent and widespread basis.

There is also an interesting table, Table 5.1, on page 5-12. This table presents the emergency maintenance costs for various components. The components are overhead lines, underground unducted cables, underground ducted cables, underground dig-in on concrete duct bank, polemount switch, pad-mount switch, submersible switch, polemount transformer, pad-mount transformer, submersible transformer, and load break elbow.

The report also provides an extensive bibliography of data sources.

This entire report is documented in detail in an electronic file as part of the documentation for Reliability of Electric Utility Distribution Systems: EPRI White Paper 1000424. The electronic document title is Guide to Reliability Planning notes.doc."

Search terms and ID: System, Data, Financial, Report, 220

Goldberg, 1987

Goldberg, S.; Norton, W.F.; Rose, V.

"Analysis of Feeder Service Reliability Using Component Failure Rates," IEEE Transactions Power Deliver, 1987, October, PWRD-2, 4, 1292-1296, IEEE

A computer based method for analysis of electric distribution feeder reliability is developed. The method utilizes component failure rates and feeder configuration in determining values for the reliability measures: Feeder Average Interruption Frequency Index, (FAIFI) and Feeder Average Interruption Duration Index, (FAIDI). The analysis method is applied to the prediction of the reliability of a Pacific Gas and Electric Company feeder. This 21 kV underground feeder, designated Stockdale 2114, was upgraded extensively during 1985. The effect on reliability of each stage of the upgrade program is evaluated and the cumulative effects on the reliability indices are predicted.

The report presents some component failure data. The data source is not documented. The report is based on a PG&E analysis, so PG&E may be the data source. On page 1295 failure data is provided for switches, distribution transformers, elbows, 10-year-old HMWPE cable, new XLPE cable, old splices, and new splices. Response time is provided in the absence of fault indicators and protection by fusing, with fault indicators but no protection by fusing, with fault indicators and protection by fusing. Repair times are provided for switches, cables, splices, elbows, and transformers.

Search terms and ID: Multiple, Technical, Data, Journal Article, 246

Gonen, 1986

Gonen, Turan

"ELECTRIC POWER DISTRIBUTION SYSTEM ENGINEERING," 1986, McGraw-Hill, New York, New York

This book is totally devoted to power distribution engineering. The author's intention was to fill a vacuum by creating a textbook focused on distribution. This book evolved from the content of courses given by the author at the University of Missouri at Columbia, the University of Oklahoma, and Florida International University. It was written for senior-level undergraduate and beginning-level graduate students, as well as practicing engineers in the electric power utility industry. The book includes topics on distribution system planning, load characteristics, application of distribution transformers, design of subtransmission lines, distribution substations, primary systems, and secondary systems; voltage-drop and power-loss calculations; application of capacitors; harmonics on distribution systems; voltage regulation; and distribution system protection and reliability. This book has been particularly written for students or practicing engineers who may want to teach themselves. Each new term is clearly defined when it is first introduced; also a glossary has been provided. Basic material has been explained carefully and in detail with numerous examples. Special features of the book include ample numerical examples and problems designed to use the information presented in each chapter. A special effort has been made to familiarize the reader with the vocabulary and symbols used by the industry. The addition of the appendixes and other back matter makes the text self-sufficient.

The book provides an extensive chapter on reliability calculations that includes good examples. It only presents one very brief table of failure rates. Table 11-10 page 642 presents normal weather failure rate, average repair time, and disastrous weather failure rate for feeder circuit breaker, distribution transformer, three-phase switch, fuse, and three-phase switch on single-phase lateral. Only the title page, contents, and preface are in the reliability library. The book can be found in the EPRI library.

Search terms and ID: System, Technical, Financial, Book, 271

Guertin, 1976

Guertin, M. B.; Albrecht, P. F.; Bhavaraju, M. P.; Billinton, R.; Jorgensen, G. E.; Karas, A.N.

"List of Transmission and Distribution Components for Use in Outage Reporting and Reliability Calculations," IEEE Transactions on Power Apparatus and Systems, 1976, July/Aug, PAS-95, 4, 1210 - 1215, IEEE

This paper identifies composite systems for which reliability calculations are performed and major components of transmission and distribution equipment for which outage data are recorded. Descriptions such as design and operating characteristics, type, application, etc. which can be used to classify or group components in analyzing outage data are also suggested. The important requirements of an outage reporting procedure are discussed in this report. The information in this paper can be used as a guide by the utility industry in setting up a standard transmission and distribution equipment data bank.

While the paper provides a useful initial step, it needs much additional detail to assure that the data collected are useful for studies of aging component failure and for application within models aimed at optimization of maintenance and replacement decisions and recognizing uncertainty in component performance. No reliability data is reported.

Search terms and ID: Multiple, Other, Journal, 258

Guertin, 1975

Guertin, M. B.; Albrecht, P. F.; Bhavaraju, M. P.; Billinton, R.; Karas, A. N.; Masters, W. D.

"Definitions of Customer and Load Reliability Indices for Evaluating Electric Power System Performance," IEEE Power Engineering Society Conference Papers from the Summer Meeting 75 CH1034-8-PWR, A 75 588-4, 1975, July 20-25, 1-5, IEEE

Paper aims to create uniformity in reporting load interruptions. Four indices are discussed: 1) customer interruption frequency; 2) connected load interruption and curtailment; 3) interruption duration; and 4) service indices.

Table I displays system data for reliability index calculations by presenting bus, number of customers served by feeders from bus and connected load data. Several additional tables display customers interrupted, load interrupted, duration and KVA minute data. Causes of interruptions are not discussed.

Search terms and ID: System, Data, Journal Article, 100

Gunderson, 1992

Gunderson, R.O.; Bhavaraju, M.P.; Billinton, R.; Klempel, D.; Klopp, M.A.; Lauby, M.G.

"Current Industry Practices in Bulk Transmission Outage Data Collection and Analysis," IEEE Transactions on Power Systems, 1992, February, 7, 158-166., IEEE

This paper focuses on the state-of-the-art of bulk transmission outage data collection and analysis. Included in this discussion is the motivation for interest in single and multiple outage event analysis, and identification of where to obtain data on weather conditions which impact the performance of bulk transmission.

Search terms and ID: Non-specific, Monitoring, Journal Article, 249

Gururaj, 1984

Gururaj, B.I.

"Overvoltages and disturbances in power distribution networks," Electrical India, 1984, November 30, 6-C-6-F

"The paper provides a survey of major trends and outstanding issues related to overvoltage and disturbances in power distribution networks. Overvoltages are classified according to duration as transient and temporary overvoltages. If caused by a specific switching operation, they are termed switching overvoltage and if caused by lightning, they are termed lightning overvoltages. The paper classifies voltage dips and fluctuations in voltage as disturbances.

In brief the paper reviews causes, existing solutions, and areas for further development as related to lightning overvoltages, switching overvoltages, characteristics of overvoltages on low voltage networks, voltage dips and fluctuations, and harmonic distortion in power distribution networks. Lastly, the paper states that rapid advances in electronic techniques have substantially increased the capabilities of instruments for use in this area; such as harmonic analysis using μP based instrumentation. The paper also provides references for further studies in each one of the discussed topics. This is an empirical study and does not suggest appropriate models or analysis methods.

Search terms and ID: Multiple, Causes, Design, Journal Article, 202

Hale, 2000

Hale, P.S., Jr.; Arno, R.G.

"Survey of reliability and availability information for power distribution, power generation, and HVAC components for commercial, industrial, and utility installations," 2000 IEEE Industrial and Commercial Power Systems, 2000, 31-54, IEEE, Piscataway, NJ

This paper presents the culmination of a 24000 man-hour effort to collect operational and maintenance data on 204 power generation, power distribution and HVAC items, including gas turbine generators, diesel engine generators, electrical switchgear, cables, circuit breakers, boilers, piping, valves, pumps, motors and chillers. The data collection process and the resultant data are the subject of this paper. The primary purpose of the data collection effort was to provide more current equipment reliability and availability data when performing a facility reliability/availability assessment. Information was obtained on a variety of commercial and industrial facility types with varying degrees of maintenance quality. Data collection guidelines and goals were established to ensure that sufficient operational and maintenance data were collected for statistically valid analysis. A database system, with flexible output capabilities, was developed to track both the equipment information and the contact information. The levels of data quality and maintenance quality were assessed during the analysis phase of the project. The results indicated that the maintenance quality level was a major predictor of equipment availability; therefore, the availability values presented represent an average maintenance program across all the data sources. In addition, the information obtained can aid facility designers and engineers in evaluating different designs to minimize production/mission failure and to estimate the down times associated with various systems or sub-systems.

"Data was collected as part of the U.S. Army Corps of Engineer's Power Reliability Enhancement Program. The data is stored in the PREPIS (Power Reliability Enhancement Program Information System) database. This is a Microsoft Access database that is available on CD. Equipment age information is included in the database, but not in the printed summary included in this document.

Data was collected for 204 components including HVAC and generation components that are not of interest to this distribution study. The focus was on equipment installed after 1971. For each component a minimum of 3.5 million calendar hours, a minimum of 40 sample components, and a minimum of 5 years of operation were required to develop the data.

The following data is provided about each component in this summary: reliability, inherent reliability, operational availability, unit years, failures, failures/year, mean time between failures, mean time to repair, mean time to maintain, mean down time, mean time between maintenance, and hours downtime per year. These data are further defined below.

These definitions are referenced in several reliability publications and the formulas can be verified in the RAC Toolkit for commercial practices, page 12, or MIL-STD-339, or in the IEEE standard definition publication. Definitions include the following:

(MDI) - Mean Down Time is the average down time caused by scheduled and unscheduled maintenance, including any logistics time.

(MTBM) - Mean Time Between Maintenance is the average time between scheduled and unscheduled maintenance, including logistics time.

(Tp) - Total Period is the Calendar time over which data for the item was collected.

(Rdt) - Repair Down line is the total Down Time for Repairs Due to failures (Unscheduled Maintenance).

(Mdt) - Maintenance Down Time is the Total Down Time for scheduled maintenance (including logistics time).

8760 - Total Hours in a Year (non-leap year).

Ao - Operational Availability considers down time for Scheduled (repair due to failures) and Unscheduled maintenance, including Logistics time. Reference RAC Toolkit. MIL-STD-338, and IEEE Dictionary.

Ai - Inherent Availability considers down time for repair to failures only, no logistics time. Reference RAC Toolkit, MIL-STD-338, and IEEE Dictionary.

Rel - Reliability calculation based on the exponential distribution. Reference RAC Toolkit, MIL-STD-338, and IEEE Dictionary.) lambda represents the failure rate of the item and t represents the period of data collection in calendar time divided by 3760.

Total_Fails - Total number of failure occurrences during the Total Period.

Total_Maint - Total number of maintenance actions (Scheduled Maintenance) during the Total Period.

MTBF - Mean Time Between Failures is the average time calculated between failure occurrences.

MTTR - Mean Time To Repair is the average time to accomplish repairs on an item

MTTM - Mean Time To Maintain is the average time to accomplish maintenance on an item

Hrdt/Yr. - (Mean Hours Down Time per Year) - Average hours the item is expected to be not functional based on a year.

Items with 0 failures, reliability statistics are calculated using the Chi Squared 60% confidence interval based on time truncated data. This common approach to data with no failures associated with the data collection time frame is explained in MIL-HDBK-338, section 8.3.2.5.2, Confidence Limits - Exponential Distribution. These items are identified by an asterisk (*) in the database report.

In the list below the calculated data name is followed by the formula.

Ao, Operational Availability -- Ao = (MTBM/MTBM+MDT)

Ai, Inherent Availability -- Ai = (MTBF/MTBF+MTTR)

Rel, Reliability -- Rel = exp(-(lambda)t)

FR, Failure Rate (per Year) -- FR/Yr. = Total Failures/Tp/8760)

MTBF, Mean Time Between Failures -- MTBF = Tp/Total_Fails

MTTR, Mean Time To Repair -- MTTR = Rdt/Total_Fails

MTTM. Mean Time To Maintain -- MTTM = Mdt/Total_Maint

MTBM. Mean Time Between Maintenance -- MTBM = Tp/All Actions, Maintenance and Repair

MDT. Mean Down Time -- MDT= (Rdt + Mdt)/All Actions, Maintenance and Repair

Hours Downtime per Year -- Hrdt/Yr. = (rpt_repair_time + rpt_maint_time)/(Tp/8760)

The following components are covered by the summary:

Arrester, lightning; battery, gel cell-sealed, system; battery, lead acid, system; battery, nickel-cadmium; bus duct, all types; cable, above ground, in conduit, < 600V; cable, above ground, in conduit, > 600V, <5kV; cable, above ground, no conduit, < 600V; cable, above ground, no conduit, > 600V, <5kV; cable, above ground, trays, < 600V; cable, above ground, trays, > 600V, <5kV; cable, aerial, <15kV; cable, aerial, >15kV; cable, below ground, duct, <600V; cable, below ground, duct, >600V, <5kV; cable, below ground, in conduit, <600V; cable, below ground, in conduit, >600V, <5kV; cable, below ground, insulated, <600V; cable, below ground, insulated, >600V, <5kV; cable, insulated, DC; cable connection, capacitor bank, power factor, corrector; circuit breaker, 600V, 3 Phase, fixed, inducting molded case, <600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 600V, 3 Phase, fixed, inducting molded case, <600 amp, normally open, Trp. Ckt. Incl.; circuit breaker, 600V, 3 Phase, fixed, inducting molded case, <600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 600V, 3 Phase, fixed, inducting molded case, >600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 600V, 3 Phase, fixed, inducting molded case, >600V, <5kV; circuit breaker, 600V, Drawout (Metal Clad), <600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 600V, Drawout (Metal Clad), <600 amp, normally open, Trp. Ckt. Incl.; circuit breaker, 600V, Drawout (Metal Clad), >600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 600V, Drawout (Metal Clad), >600 amp, normally open, Trp. Ckt. Incl.; circuit breaker, 5kV, Vaccuum, <600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 5kV, Vacuum, <600 amp, normally open, Trp. Ckt. Incl.; circuit breaker, 5kV, Vacuum, >600 amp, normally closed, Trp. Ckt. Incl.; circuit breaker, 5kV, Vacuum, >600 amp, normally open, Trp. Ckt. Incl.; Control Panel, Switchgear controls; fuse, >5kV, < 15kV; fuse, 0-5kV; inverters, all types; meter, electric; rectifiers, all types; switch, automatic transfer, > 600 amp, < 600 volt; switch, automatic transfer, 0-600 amp, < 600 volt; Switch, disconnect, enclosed, <600V; Switch, disconnect, enclosed, >5kV; Switch, disconnect, enclosed, >600V, <5kV; switch, disconnect, fused, DC, >600 amp, < 600V, switch, disconnect, fused, DC, 0-600 amp, < 600V, switch, electric, on/off breaker type, non-knife, < 600V; switch, float, electric; switch, manual transfer, < 600amp, < 600V, switch, manual transfer, >600amp, < 600V; switch, oil filled, >5kV; switch, static, >1000amp, <600V; switch, static, >600 amp, <1000amp, <600 V; switch, static, 0-600 amp, <600V; switchgear, bare bus, <600V, all cabinets, Ckt. Bkrs. Not included; switchgear, bare bus, >5kV, all cabinets, Ckt. Bkrs. Not included; switchgear, bare bus, >600V, <5kV, all cabinets, Ckt. Bkrs. Not included; switchgear, insulated bus, <600V, all cabinets, Ckt. Bkrs. Not included; switchgear, insulated bus, >5kV, all cabinets, Ckt. Bkrs. Not included; switchgear, insulated bus, >600V, <5kV, all cabinets, Ckt. Bkrs. Not included; transformer, dry, air cooled, <500kVA; transformer, dry, air cooled, >1500kVA, <3300kVA; transformer, dry, air cooled, >500kVA, <1500kVA; transformer, dry, isolation, Delta Wye, <500kVA; transformer, liquid, forced air, <10,000kVA; transformer, liquid, forced air, <5,000kVA; transformer, liquid, forced air, >10,000kVA, <50,000kVA; transformer, liquid, non-forced air, <3000kVA; transformer, liquid, non-forced air, >10,000kVA, <50,000kVA; transformer, liquid, non-forced air, >3000kVA, <10,000kVA; UPS, rotary; UPS, small computer room floor; Voltage Regulator, static

Search terms and ID: Multiple, Data, Proceedings, 230

Hamman, 1995

Hamman, J.

"Experience with the Use of RCM in a Transmission Maintenance Environment," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 192-197, IEE, Norwich, United Kingdom

Reliability Centered Maintenance (RCM) moves beyond time-based maintenance to take the level of usage and condition of equipment into account. This paper provides a summary of RCM as applied to two pilot programs. RCM stands to be an important training tool because so many disparate parties are involved, each sharing knowledge.

Search terms and ID: System, Technical, Proceedings, 77

Harness, 2000

Harness, R.E.

"Steel distribution poles and their environmental implications," Industry Applications, 2000, May/June, 6, 3, 53-56, IEEE

Utilities increasingly employ steel distribution poles in their new low-voltage construction partially because steel offers certain environmental advantages over wood. First, steel poles are not susceptible to woodpecker damage. In some regions of the US, woodpecker damage is the most significant cause of wood pole deterioration. Second, steel poles are harder for animals such as eastern fox squirrels (Scirius niger), raccoons (Procyon lotor), and opossums (Didelphis marsupialis) to climb. Keeping animals off utility structures can help reduce outages. Although steel can rust, it is not susceptible to fungal, bacterial, and insect damage. Finally, steel is recyclable.

Contains no useful data. Discusses the electrocution dangers that steel utility poles pose for raptors and other birds. Search terms and ID: Poles, Other, Journal Article, 233

Hartwrigh, 1995

Hartwrigh, R.; Coffey, J.

"Improvement of Customer Service by System Automation, The," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 127-132, IEE, Norwich, UK

Paper discusses improving power delivery standards through system automation.

The paper itself has little to do with reliability of aging assets, but Figure 1 displays the customer minutes lost due to faults at various voltage levels.

Search terms and ID: System, Data, Proceedings, 70

Heising, 1974

Heising, C. R.

"Reliability of Electric Power Transmission and Distribution Equipment," Twenty-Eighth Annual Technical Conference Transactions of the American Society for Quality Control, 1974, May, 314-319

Notes a need for reliability analysis of transmission and distribution system based upon economics. The results would be a guide to both utilities making decisions about system design and maintenance and for manufacturers making decisions about design and cost. After introducing the topic, the author describes analyses from Sweden and France that make use of the failure rates, repair times, and the value of undelivered energy to calculate the value of more reliable equipment. The following sections discuss the availability of data in the US, the importance of estimates of outage times, and failure modes of circuit breakers.

The paper includes a summary of the data from "Report on Reliability Survey of Industrial Plants, Part 1 - Reliability of Electrical Equipment," 1973. This data appears in a Table on page 317. The Table provides Failure rate, industry average downtime per failure, and median plant average downtime per failure for the following items: ELECTRIC UTILITY POWER SUPPLIES Single Circuit; TRANSFORMERS, Liquid Filled-All, 601 - 15,000 Volts, Above 15,000 Volts, Dry Type; 0 - 15,000 Volts, Rectifier; Above 600 Volts; CIRCUIT BREAKERS, Fixed Type (inlc. molded case) All, 0 - 600 volts, Above 600 Volts, Metalclad Drawout - All, 0 - 600 Volts, Above 600 Volts; MOTOR STARTERS, Contact Type; 0 - 600 Volts, Contact Type; 601 - 15,000 Volts; MOTORS, Induction; 0 - 600 Volts, Induction; 601 - 15,000 Volts, Synchronous; 0 - 600 Volts, Synchronous; 601 - 15,000 Volts, Direct Current – All; GENERATORS, Steam Turbine Driven, Gas Turbine Driven; DISCONNECT SWITCHES, Enclosed; SWITCHGEAR BUS, Insulated; 601 - 15,000 Volts, Bare; 0 - 600 Volts, Bare; 601 - 15,000 Volts; BUS DUCT (Unit = One Circuit Foot), All Voltages; OPEN WIRE (Unit 1,000 Circuit Feet), 0 - 15,000 Volts, Above 15,000 Volts; CABLE (Unit 1,000 Circuit Feet), Above Ground & Aerial, 0-600 Volts, 601 - 15,000 Volts - All, In Trays Above Ground, In Conduit Above Ground, Aerial Cable, Below Ground & Direct Burial, 0-600 Volts, 601 - 15,000 Volts - All, In Duct or Conduit Below Ground, Above 15,000 Volts.

Search terms and ID: Multiple, Data, Financial, Proceedings, 255

Henry, 1988

Henry, George E.

"Method for Economic Evaluation of Field Failures such as Low-Voltage Side Lightning Surge Failure of Distribution Transformers, A," IEEE Transactions on Power Delivery, 1988, April, 3, 2, 813-818, IEEE

A statistical model using life-cycle costing techniques is presented to estimate failure costs of transformers. The model is reliant on an assumed uniform annual failure rate.

Equations involved in the statistical model are presented. No failure data is presented. Discussions regarding the author's model are included. Both discussion summaries point out faults created by the simplicity of the model.

Search terms and ID: Transformers, Financial, Model, Journal Article, 107

Horton, 1991(1)

Horton, William F.; Goldberg, Saul

"Determination of Failure Rates of Underground Distribution System Components From Historical Data," Proceedings of the 1991 IEEE/PES Transmission and Distribution Conference & Exposition, 1991, September 22-27, 719-723, IEEE

Failure rates for unjacketed cable, transformers and load break rubber elbows are computed from historical data. Such calculations can be made if the data is complete (i.e. contains records of first installation and the number of failures during each year of the record).

"The historical data are from San Diego Gas and Electric Company and the Northwest Electric Light and Power Association (NELPA). NELPA is composed of seven northwestern utilities. The data cover over 20 years of service experience.

Table 1 refers to 24 years of experience and 3800 miles of SDG&E data for HMWPE 15 kV unjacketed cable. The failure rate is given by: f(t)=0.65t^0.3. Table 1 rows are years (1963-1987) and columns are cumulative miles of cable, miles of cable installed, annual failures, cumulative failures, and calculated cumulative failures. The data is plotted in Figure 1.

Table 2 refers to 20 years of experience and 5800 miles of NELPA data for XLPE 15 kV 175 mil unjacketed cable. The failure rate is given by: f(t)=0.65. Table 2 rows are years (1968-1988) and columns are cumulative miles of cable; miles of cable installed, annual failures, cumulative failures, and calculated cumulative failures. The data is plotted in Figure 2.

Similar calculations for 18 years of experience and 2900 miles of NELPA data for XLPE 15 kV 220 mil unjacketed cable. The failure rate is given by: f(t)=0.13.

Table 3 refers to 20 years of experience and over 88,000 single-phase pad mounted transformers at NELPA utilities. The failure rate is given by: f(t)=(3X10^-3)t. Table 3 rows are years (1968-1988) and columns are cumulative units, units installed, annual failures, cumulative failures, and calculated cumulative failures. The data is plotted in Figure 3

Table 4 refers to 20 years of experience and over 364,000 load break rubber elbows at NELPA utilities. The failure rate is given by: f(t)=(0.09X10^-3)t. Table 4 rows are years (1968-1988) and columns are cumulative units, units installed, annual failures, cumulative failures, and calculated cumulative failures. The data is plotted in Figure 4 "

Search terms and ID: Multiple, Data, Technical, Proceedings, 41

Horton, 1991(1)

Horton, William F.; Goldberg, Saul; Volkmann, C.A.

"Failure Rates of Overhead Distribution System Components, The," Proceedings of the Transmission and Distribution Conference, 1991, September, 713-717, IEEE, New York, NY

A 5-year (1984-1989) study of 85 rural and 95 urban non-mountain overhead (OH) distribution feeders in the PG&E system is described. Generic service time failure rates for transformers, switches, fuses, capacitors, reclosers, voltage regulators, and conductor were obtained. The failure rates detailed represent contribution rates to feeder interruptions. The data excludes secondary interruptions so transformer failure rates are relatively lower than might be expected. These failure rates are in reality best estimates of the actual failure rates of the components. A range of deviations about these best estimates can be assessed at various confidence levels. Only transformers were found to exhibit a significant difference in failure rate between rural and urban installations. The component failures contributed about 15% of the total number of sustained outages for the OH feeders of this study. The remaining 85% of the sustained outages were due to external factors (75%) and loss of supply (10%). This suggests that an overhead distribution system is relatively insensitive to component failures, at the existing component failure rate levels.

"Data was from PG&E in the period 1984 to 1989.

Rural data was from 85 feeders with 380 feeder years of data and the following components: 33,686 transformers, 1233 switches, 2491 fuses, 207 capacitors, 149 reclosers, 59 voltage regulators, 7465 mile of conductor.

Urban data was from 95 feeders with 389 feeder years of data and the following components: 18,522 transformers, 1858 switches, 2016 fuses, 338 capacitors, 50 reclosers, 8 voltage regulators, 2439 mile of conductor.

Table 1 presents rural and urban failure rates for each component above."

Search terms and ID: Multiple, Data, Technical, Proceedings, 47

Horton, 1979

Horton, W. F.; St. John, A. N.

"Failure Rate of Polyethylene Insulated Cable, The," 7th IEEE/PES Transmission and Distribution Conference and Exposition, 79CH1399-5-PWR, 1979, April 1-6, 324-328, IEEE

Paper discusses the failure rate of underground polyethylene cables. The authors argue that failure rates should be expressed as a function of the time that the cable is in service. Wide differences in failure data are due to the fact that failures are a function of time and not constant.

The paper begins with an explanation of equations that represent cable failures as a function of time. Table 1 displays 35-kV cable (polyethylene) and crosslinked polyethylene failures as a function of the year installed, the conductor feet installed that year and conductor feet cumulative. Tables 2 and 3 display polyethylene cable and cross-linked polyethylene conductor miles installed, calculated cumulative failures at year-end and reported cumulative failures at year-end. Figures 1 and 2 display reported and calculated cumulative failures at year-end versus time (in years) for PE and XPE cables. Tables 4 and 5 display SDG&E #2 and 4/0 AWG copper 220 mil polyethylene cable conductor miles installed in year, conductor miles removed the same year, calculated cumulative failures at year end and reported cumulative failures at year end. Figures 3 and 4 display reported and calculated cumulative failures at year-end versus time (in years) for SDG&E #2 and 4/0 AWG copper 220-mil polyethylene cable.

Search terms and ID: Cables, Data, Equations, Journal Article, 113

Hoskins, 1999

Hoskins, R.P.; Strbac, G. ; Brint, A.T.

"Modeling the Degradation of Condition Indices," IEEE Proceedings, 1999, July, 146, 4, 386-392, IEE

"The paper observes that the majority of networks are approaching their 35-40 year envisaged lifespan. Most assets have been subject to regular preventive maintenance, which makes failures rare and inference about future lifetimes difficult. The paper argues that in such situations, importance should be given to obtaining condition information to aid asset management. In this connection, some issues that are presently receiving attention are the time schedule and extent of network replacements, the impact on risk and cost in extending the interval of a time-based maintenance policy, and the effect of a particular asset management policy on the future condition of network assets.

Since most structured approaches to formulating asset management decisions require information detailing the condition of the assets, modeling condition information has become a vital component in asset management. The paper both discusses possible data structures such as subjective overall ratings, overall performance indices, and separate component measures, and details of Markov condition modeling after arguing its suitability for condition modeling. Different aspects of Markov models and estimation procedures are discussed and the technique is applied to oil condition modeling of oil-filled switchgear data. The paper further illustrates the impact of such modeling in making better asset management decisions.

The paper does not measure the risk associated with extending the interval of a time-based maintenance policy. The authors do not address what appears to be a fundamental issue: what is the optimal time between maintenance events, and what should be maintained or what is the optimal level of maintenance? Further, the paper does not specifically address the consequences of doing nothing.

The need for a model based on component conditions is advocated. A Markov model describing asset management (AM) decisions based on the deterioration of oil will provide an indication of the deterioration of equipment. Two Markov methods, the maximum likelihood approach and least square approach, are presented. State probabilities, risk of being in a particular state, and probability distribution of time to enter a state can be computed."

Table 5 presents state transition probabilities relating to four states of oil condition in the switches. A Markov process is suggested due to its application to similar problems. Markov models may have to be re-examined after more data becomes available. Case study and appendix on Markov modeling provided.

Search terms and ID: Switches, Technical, Data, Journal Article, 34

Hsu, 1990

Hsu, Y.Y.; Chen, J.L.; Chen, L.M.

"Application of a Microcomputer-Based Database Management System to Distribution System Reliability Evaluation," IEEE Trans. on Power Delivery, 1990, Jan, 5, 1, 343 - 350, IEEE

The experience with the application of a database management system (DBMS) to handle the large amounts of data involved in distribution system reliability evaluation is reported. To demonstrate the capability of the DBMS in data manipulation, reliability evaluation of a distribution system in Taiwan is performed using a DBMS installed on an IBM PC/AT. It is found that using DBMS tool is a very efficient way of organizing data required by distribution planners. Moreover, the DBMS method is very cost-effective since it is installed on a personal computer.

No component level failure data is presented. Calculated indices such as SAIFI, CAIDI, etc. are provided for individual feeders to illustrate the uses and outputs of the database analysis system.

Search terms and ID: System, Technical, Journal Article, 247

IEEE, 1974(1)

IEEE

"Report on Reliability Survey of Industrial Plants, Part VI: Maintenance Quality of Electrical Equipment, Correction to," IEEE Transactions on Industry Applications, 1974, Sept./Oct., 1A-10, 5, 681, IEEE

Table of population of electrical equipment versus maintenance quality and normal maintenance cycle. Addendum to a paper previously presented in the Journal.

Table 64 presents transformer, circuit breaker, motor starter, motor, generator, and disconnect switch maintenance cycles. Maintenance quality for each component is rated as excellent, fair, poor or none.

Search terms and ID: System, Maintenance, Journal Article, 106

IEEE, 1974(2)

IEEE

"Report on Reliability Survey of Industrial Plants, Part III: Causes and Types of Failures of Electrical Equipment, the Methods of Repair, and the Urgency of Repair," IEEE Transactions on Industry Applications, 1974, March/April, 1A-10, 2, 242-252, IEEE

Paper presents failure types and methods of repair from a reliability survey of 68 industrial plants in the United States and Canada. Specifically presented are failure repair methods; failure repair urgency; failure, months since last maintained; failures, damaged parts; failure type; suspected failure responsibility; failure initiating cause; failure contributing cause; and failure characteristics.

Table 31 displays the number of failures for electric utility power supplies by type. Table 32 displays the number of failures for each main equipment class. Tables 33 through 41 display failure repair methods, failure repair urgency, months between failures and last maintenance, damaged parts, failure types, suspected failure responsibilities, failure initiating causes, failure contributing causes, and failure characteristics for electric power supplies, transformers, circuit breakers, motor starters, motors, generators, disconnect switches, switchgear bus - bare, bus ducts, open wires, cables, cable joints, and cable terminations. Table 42 displays simultaneous failures of all circuits in electric utility suppliers. Table B displays failures as a function of preventative maintenance and time. An unlabeled table displays the percentage of electric power distribution components culpable for system failures.

Search terms and ID: System, Causes, Data, Journal Article, 109

IEEE, 1974(3)

IEEE

"Report on Reliability Survey of Industrial Plants, Part IV: Additional Detailed Tabulation of Some Data Previously Reported in the First Three Parts," IEEE Transactions on Industry Applications, 1974, July/August, 1A-10, 4, 456-462, IEEE

Paper presents data from a reliability survey of 68 industrial plants in the United States and Canada.

Table 43 presents failure modes of metal clad drawout and fixed type circuit breakers for varying voltages. Tables 44 and 45 present cost of power outage data. Tables 48 to 50 present the data regarding the effect of failure repair methods and failure repair urgency for liquid-filled transformers, metal clad drawout circuit breakers, motors and cables for various voltages. Tables 51 through 56 present data regarding downtime due to failures.

Search terms and ID: System, Data, Causes, Journal Article, 110

IEEE, 1974(4)

IEEE

"Report on Reliability Survey of Industrial Plants, Part V: Plant Climate, Atmosphere, and Operating Schedule, the Average Age of Electrical Equipment, Percent Production Lost, and the Method of Restoring Electrical Service after a Failure," IEEE Transactions on Industry Applications, 1974, July/August, 1A-10, 4, 463-466, IEEE

Paper presents climate, atmosphere, age, operating schedule, etc. data from a reliability survey of 68 industrial plants in the United States and Canada.

Table 58 presents percent production lost and total failures reported for transformers, circuit breakers, motor starters, motors, generators, disconnect switches, switchgear bus - bare, bust ducts, open wires, cables, cable joints, and cable terminations. Table 60 presents the average age of electrical equipment reported for transformers, circuit breakers, motor starters, motors, generators, disconnect switches, switchgear bus - bare, bus ducts, open wires, cables, cable joints, and cable terminations.

Search terms and ID: System, Data, Causes, Journal Article, 111

IEEE, 1974(5)

IEEE

"Report on Reliability Survey of Industrial Plants, Part VI: Maintenance Quality of Electrical Equipment," IEEE Transactions on Industry Applications, 1974, July/August, IA-10, 4, 456-462, IEEE

Paper presents maintenance quality, schedule maintenance and failure due to inadequate maintenance data from a reliability survey of 68 industrial plants in the United States and Canada.

Table 64 presents switchgear bus (insulated and bare), open wire, cable, cable joints and cable termination maintenance cycles. Maintenance quality for each component is rated as excellent, fair, poor or none. Tables 65 and 66 present maintenance quality and maintenance cycle time for transformers, circuit breakers, motor starters, motors, generators, disconnect switches, switchgear bus - bare, bust ducts, open wires, cables, cable joints, and cable terminations. Tables 67 through 78 displays the number of transformer, circuit breaker, motor starter, motor, generator, disconnect switch, switchgear bus - bare, bus duct, open wire, cable, cable joint, and cable termination failures versus the number of months since maintained and maintenance quality. Tables 79 and 80 present the number of failures versus maintenance quality and months since maintained for all equipment classes combined.

Search terms and ID: System, Data, Causes, Journal Article, 112

IEEE, 1974(6)

IEEE

"Report on Reliability Survey of Industrial Plants, Part I: Reliability of Electrical Equipment," IEEE Transactions on Industry Applications, 1974, March/April, IA-10, 2, 213-235, IEEE

Paper presents reliability data from a reliability survey of 68 industrial plants in the United States and Canada.

Several equations used in the statistical analysis of equipment failure data are presented. Figure 1 presents failure rate confidence levels for the collected data. Table 2 presents equipment failure rate and equipment outage duration data. Included in Table 2 are failure rate, downtime per failure and average estimated clock hour to fix failures data for electric utility power supplies; transformers; circuit breakers; motor starters; motors; generators; disconnect switches; switchgear buses; bus ducts, open wires; cables; cable joints; cable terminations and other miscellaneous components. Tables 3 through 18 present sample size, number of failure, industry, equipment, failure rate and actual downtime data for electric utility power supplies; transformers; circuit breakers; motor starters; motors; generators; disconnect switches;

switchgear buses; bus ducts, open wires; cables; cable joints; cable terminations and miscellaneous equipment. Appendix A contains a copy of the survey used to obtain the data.

Search terms and ID: System, Data, Causes, Journal Article, 119

IEEE, 1968

IEEE

"Proposed Definitions of Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions," IEEE Transactions on Power Apparatus and Systems, 1968, May/June, PAS-87, 5, 1318-1323, IEEE

Paper presents suggested definitions for describing outages of transmission and distribution facilities and interruptions to customers. Discussions are presented arguing the merits of the proposed definitions.

No real data is presented. Proposed definitions are divided into three groups: General Terms, Outage Terms, and Interruption Terms.

Search terms and ID: System, Data, Journal Article, 116

IEEE/PES Task Force on Impact of Maintenance Strat., 1999

IEEE/PES Task Force on Impact of Maintenance Strat.

"Impact of Maintenance Strategy on Reliability," 1999, July, IEEE

The agenda of the report is to educate the electrical industry about reliability-centered maintenance (RCM). The paper describes deterministic and probabilistic models to determine maintenance policies. The report covers in great detail definitions of ageing, failures, deterioration, repair and maintenance, etc., and the classification of failures. Ageing and maintenance

Although no specific data are presented, ageing and maintenance are covered in depth, including definitions of failures and the stages of deterioration. Deterioration is delineated by two definitions: deterioration by way of duration or physical signs (corrosion, wear, etc.). Of particular interest are the inclusion of simple state diagrams for mathematical models based on ageing failures for differing maintenance schedules and state diagrams for random and deterioration failures. The report states that probabilistic models for reliability are superior but recognizes that models (probabilistic or otherwise) are rarely used. The report also highlights that maintenance is done particularly during times when energy prices are low, and thus when it's more economically feasible. The survey questions the researchers used to generate data on maintenance policies were included.

Search terms and ID: Multiple, Maintenance, Monitoring, Report, 17

Jones, 1987

Jones, T.L.; Kogan, V.I.

"Application of operations research to the failure associated problems of URD cables," 14th Inter-RAM: International Reliability, Availability, Maintainability Conference for the Electric Power Industry, 1987, 282-9, Pennsylvania Power & Light Co, Wescoville, PA

The failure data of a subsample of 15 kV URD cables on the AEP System are analyzed to establish their optimum economic life. The nonhomogeneous Poisson process was adapted as the failure model for repairable URD cables. The Gompertz distribution was favorably compared to the Weibull as the applicable failure distribution. Three different repair-replacement policies were considered and applied with results compared to each other. A sensitivity study for Policy III was incorporated and practical recommendations were made. The whole study is based upon the operations research approach and is of a very general nature with wide applicability to optimal repair-replacement decisions.

"AEP data from Indiana mostly of high molecular weight polyethylene insulated cables. Assumed homogeneous cables and similar stresses. Figure 1 plots year versus miles of cable and year versus failures for 1969 to 1985. Figure 2 compares the number of miles installed in each year to the number of failures experienced by each vintage. Table 1 reports age, number of units, reported failures, number of new units, units replaced, and adjusted number of failures. Using these data maximum likelihood estimates of the parameters of Weibull and Makeham-Gompertz distributions for the failures are estimated. These parameter values are provided in the paper. These estimates were highly unstable depending on the starting point for the numerical solution. The authors also solved for parameters using a modified method-of-moments procedure. These parameter estimates were more stable.

The parameter fitting approach may also be of interest."

Search terms and ID: Cables, Technical, Data, Proceedings, 238

Kariuki, 1995

Kariuki, K.K.; Allan, R.N.

"Reliability Worth In Distribution Plant Replacement Programmes," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 162-167, IEE, Norwich, UK

Paper challenges the notion that replacement should be based solely cost-benefit analyses, and suggests that technical criteria such as reliability be considered. Models show that the Incremental System Customer Outage Costs should be considered as part of cost-benefit analyses when determining the replacement of distribution system components.

Model-generated data is presented. Table 2 summarizes the qualitative effects of asset replacement in terms in the changes in average failure rate, average outage duration and number of customers affected. Tahle 4 displays model-generated replacement scenarios and delta SCOC.

Search terms and ID: System, Financial, Technical, Proceedings, 74

Kelley, 1999

Kelley, Arthur; Edwards, Steven; Rhode, J.P.; Baran, M.E.

"Transformer Derating for Harmonic Currents: A Wide Band Measurement Approach for Energized Transformers," IEEE Transactions on Industry Applications, 0093-9994, 1999, Nov/Dec, 35, 6, 1450-1457, IEEE

A review of IEEE Recommended Practice C57.110 regarding the derating of transformers using calculations based on dc winding resistance and rated load loss. The authors present an alternative method to C57.110 based on direct measurement performed at fundamental and harmonic frequencies that can be performed whether or not the transformer is energized and in service.

Paper discusses transformer derating in detail and presents several equations regarding eddy-current loss, etc., used in the derating process. Data from a finite element test model is presented. The data for both primary and secondary winding include number of turns, number of layers, turns per layer, wire gauge, effective conductor thickness, window height, length of winding turn, and dc winding resistance. Test result data for the FEA model also include magnetic field and current density for dc and 8 kHz. Graphs are also presented for effective ac resistance versus frequency and effective ac inductance versus frequency. Table II displays the distribution transformer data of primary and secondary transformer resistance for 10, 50 and 100 kVA transformers. Table III displays measured resistances at harmonic frequencies for 10, 50 and 100 kVA transformers.

Search terms and ID: Transformers, Causes, Technical, Journal Article, 87

Kogan, 1996

Kogan, V. I.; Roeger, C. J.; Tipton, D. E.

"Substation Distribution Transformers Failures and Spares," IEEE Transactions on Power Systems, 1996, November, 11, 4, 1905-1912, IEEE

"Electric utilities should have a sufficient number of spare transformers to backup substation distribution transformers to replace transformers that fail and require factory rebuild or replacement. To identify such a number, the statistical methodology was developed to analyze available failure data for different groups of transformer. That methodology enables the estimation of future numbers of failures with associated probabilities, recommends the proper number of spares, identifies the necessity and shows the means to shorten the transformer's replacement time.

Paper discusses the use of homogeneous Poisson process (HPP) statistical methods to analyze transformer failure data in order to determine a sufficient number of spare transformers necessary to keep systems running in the event of a failure. "

Equations behind the HPP methodology are presented. Data from example calculations is presented. Tables 1.1, 1.2, 8 and 10 display factory repairable or scrap failures and exposure risk for a group of 69 13 kV transformers. Other tables display probabilities of expected failures for experimental data.

Search terms and ID: Transformers, Technical, Equations, Journal Article, 98

Kogan, 1994

Kogan, V. I.; Jones, T. L.

"Explanation for the Decline in URD Cable Failures and Associated Nonhomogeneous Poisson Process, An," IEEE Transactions on Power Delivery, 1994, January, 9, 1, 534-543, IEEE

The possible need to remove from service approximately 2000 miles of high molecular weight polyethylene URD cable has been a topic of concern at American Electric Power. Earlier projections indicated that failures would increase at an exponential rate and that a typical section of cable would be replaced prior to reaching 30 years of age. However, data analysis shows a downward trend in failures after a cable system has been operating for about 18 years. A possible explanation for this finding is the elimination of cable defects through the failure repair (splicing) process. The authors' findings suggest that, in addition to age and failure history, the decision to remove a cable section from service should be based on the condition of the cable after repair.

Tables I and II display the number of 15 kV HMW URD cable failures and number of cable runs removed from service by the year if installation for the Roanoke Division (1984-1991) and St. Joseph Division (1972-1991). Table III displays the number of cable runs with first repeated failures over life of run and n number of isolating devices with repeated operations over one year period, respectively, by installation year for the Roanoke Division, 1984-1991. Figures 1 and 2 display the expected number of failures on one standard cable run during one year interval by age at failure for the Roanoke Division, 1984-1991 and St. Joseph Division, 1969-1991, respectfully (both show increasing failures to a point of time, and then a decrease in failures). Figures 3 and 4 display the number of reported failures and number of cable runs removed from service by report year for the Roanoke Division, 1984-1991 and St. Joseph Division, 1982-1991, respectfully. Additionally, several equations regarding the nonhomogeneous Poisson process are provided.

Search terms and ID: Cables, Equations, Data, Journal Article, 94

Koglin, 1983

Koglin, H.J.; Roos, E. ; Wellssow, W.H.

"Application of Reliability Calculation Methods to Planning of High Voltage Distribution Networks," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 64-67, IEE, London, United Kingdom

Paper outlines method to calculate reliability indices for substations and to use these indices in the network planning process. The network reliability calculation relies upon data, modeling, methods, and values.

Parameters were estimated by analyzing over 1000 observed outages. No information is provided on the time frame of the outages or the number of components. Contains an input Table for modeling that includes frequency of outages, duration of outages, conditional probabilities for lines, cables, transformers, and busbars. Outages are classified as independent outages, multiple earth faults, missing operation of protection, scheduled outage of reserve components, and multiple line faults.

Search terms and ID: Multiple, Financial, Data, Proceedings, 3

Kostyal, 1982

Kostyal, S.J.; Vismor, T.D.; R. Billinton

"Distribution System Reliability Handbook," EL-2651, 1356-1, 1982, December, EPRI, Palo Alto, California

The objectives of this research project are a compilation and an organization of reliability assessment techniques in use in 1981. A 3-volume final report (see below, EL-2018) documents the research. This practical distribution handbook for EPRI client utilities arose from the project. It describes the assessment models in detail, models for historical reliability assessment

(HISRAM) and predictive reliability assessment (PRAM), which were successfully tested and executed at two utilities. It also includes practical guidelines for reliability assessment. It contains an extensive bibliography on distribution system reliability evaluation grouped into (a) analysis and applications, (b) outage data, and (c) reliability economics and indices; including abstracts for the most significant articles.

"Provides data only as needed for examples. Page 4-13 provides illustrative failure rates and repair times for mains and laterals. Page 4-23 provides illustrative failure rates and repair times for lines, breakers, transformers, and buses. Page 4-33 provides illustrative failure rates and repair times for lines, breakers, and transformers for both normal and adverse weather.

Contains an extensive reference list of sources of failure data. We will attempt to collect these articles."

Search terms and ID: System, Financial, Technical, Report, 219

Krishnasamy, 1994

Krishnasamy, S.G.; Kulendran, S.

"Reliability analysis of an existing distribution line," Probabilistic Methods Applied to Power Systems. 4th PMAPS, 1994, September, 435-447, World Energy Council, Rio de Janeiro, Brazil

A method is presented to calculate the reliability of an existing wood pole distribution line. The purpose of this method is to provide the maintenance engineer a tool to identify individual poles, which do not meet the specified reliability requirements. The method calculates the reliability of each individual pole as well as the overall reliability of the line using the actual measured pole strength and other line details.

The outline of the method is sketchy and the presentation of the results is unclear.

Search terms and ID: System, Technical, Proceedings, 270

Kumar, 1996

Kumar, Dhananjay; Westberg, Ulf

"Proportional Hazards Modeling of Time-Dependent Covariates Using Linear Regression: A Case Study," IEEE Transactions on Reliability, 0018-9529, 1996, September, 45, 3, 386-391, IEEE

Covariates are assumed to be time-dependent in proportional hazard models. The authors present a graphical method based on a linear regression model to determine the validity of that assumption. The slope of the graphical representation can show if the covariate in question is time dependent or not. The linear regression model showed that some covariates were indeed time dependent. The method is suggested as a supplement to proportional hazards models. Covariates include, but are not limited to, operating environments (temperature, dust, pressure, humidity), operating history (overhauls, effect of repairs or preventative maintenance), and types of design or materials used.

Equations are presented to lay the foundations of proportional hazard models and the Aalen Linear Regression Model. Data for the paper is from a mining operation in Sweden. Figure 2 displays the average failure time in hours versus the failure number. Table 1 shows the results of probabilistic hazard models and linear regression models, displaying the covariate, Cox regression coefficient, Cox Model t-statistic and LRM TST. Figure 3 shows the cumulative regression functions versus time for different covariates (cable type, first failure number, and new welded joint). Table 3 displays the results of proportional hazards model, with covariate versus Cox regression coefficient and Cox model t-statistic.

Search terms and ID: Cables, Equations, Technical, Journal Article, 88

Kurunsaari, 1999

Kurunsaari, Sami

"Asset management system built from scratch," Transmission & distribution world, 1999, April, NA

Describes WorkMap, a database system developed by IVO TE of Finland, for describing all components of a distribution and transmission system and tracking maintenance and monitoring activities for the components.

Search terms and ID: System, Monitoring, Maintenance, Journal Article, 214

Lapworth, 1995

Lapworth, J.A.; Jarman, P.N.; Funnell, I.R.

"Condition Assessment Techniques for Large Power Transformers," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 85-90, IEE, Norwich, UK

Paper discusses the monitoring and diagnosis of large power transformers. Methods such as oil analysis, winding movement detection, etc., are discussed. Has a very detailed discussion of tests and their uses.

Paper contains secondary transformer fault data. Figure 1 presents a graph of arcing faults as a function of gas level versus date sampled. Table 2 displays failed transformer low frequency response.

Search terms and ID: Transformers, Monitoring, Proceedings, 69

Lebow, 1998

Lebow, M.A.; Vainberg, M.

"Asset Management Planner," Proceedings of the American Power Conference, 1998, 1, 435-440

"Asset Management Planner (AMP) is a quantitative probabilistic program that can evaluate optimum lifecycle costs of equipment. It incorporates the purchasing, minor repair costs, major repair costs, and the duration of inspections, repairs and failures. The authors discuss improvements in AMP to incorporate probability densities. Output can be displayed as sensitivity analyses for expected time of failure as a function of time between inspections. The Average Life Repair Cost (ALRC) is also discussed.

The paper describes a computer program based on a probabilistic approach to asset management. The planner can provide input to reliability-centered management (RCM) and other qualitative methodologies. The central premise of the AMP model is that equipment aging can be represented by discrete stages. The model describes the maintenance of a population of equipment and consists of the states the equipment can assume and the transition among them. A Markov process is used for the model and the rates associated with the transitions are assumed constant. Three equipment states are assumed: initial, minor deterioration, major deterioration, and failure. Repair after failure returns the device to the initial stage. In the proposed model, regular inspections are conducted and as a result decisions are made to perform minor maintenance, major maintenance, or do nothing. The inputs to the program are chance probabilities (probability of transition from one state to another) and choice probabilities (probability of making one of the three decisions being in each one of the states) that are either estimated from historical records or supplied by the user.

The tool generates the state probabilities, the shortest mean times the process can move from one state to another, and with further mathematical manipulation, answers such questions as "what is the probability that the device will not fail in the next 6 months, given that it has already reached the third deterioration stage?"

The tool allows study of the effects resulting from changes in several controllable parameters such as frequency of inspections and repair times, and aids establishing optimal policies. The authors report new developments being implemented that allow for calculation of probability distributions of time to failure (rather than the mean values). This enables the decision-makers to study the effect of maintenance policies on, for example, the number of years before failure occurs at some risk level, which can be set as a probability threshold by the user. The authors present an example of the application of the program to 230 kV air blast breakers.

"

Example analysis of 230-kV air-blast breakers with a total operating history of 100 breaker-years. The time period is not specified. Shows transition probabilities among four defined Markov states. Figure 4 shows transition times to inspection interval. Figure 6 shows the cumulative probability function of the remaining life of the breakers in years from the major deterioration state. Figure 7 shows the unavailability of the breaker as a function of the time to inspection in the minor deterioration state. Equipment aging can be represented by discrete stages. Repair after failure returns a device to an "as new" condition.

Search terms and ID: Switches, Technical, Data, Journal Article, 25

Li, 1999

Li, W; Vaahedi, E; Mansour, Y.

"Determining Number and Timing of Substation Spare Transformers Using a Probabilistic Cost Analysis Approach," IEEE Transactions on Power Delivery, 1999, July, 14, 3, 934-939, IEEE

"Compared to the N-1 security design principle in each substation, common spare transformers shared by multiple substations can avoid considerable capital expenditure and still assure a sufficient reliability level. Using common spare transformers has been already a practice of some electric utilities in distribution substation transformer planning. This paper presents a probabilistic approach to determining the number and timing of spare transformers shared in a substation group. The proposed approach is based on the aging failure model of transformers, the overall reliability analysis and the probabilistic damage cost model for a substation group, and the capital cost model for spares and the present value method. The spare transformer scheme obtained using the presented approach provides both cost efficiency and sufficient reliability. A single transformer substation group in a nonurban region is given as an application example to illustrate the procedure of the method.

Probabilistic approach based on aging failure model, reliability analysis, and probabilistic damage cost model are used to determine the number and timing of spare transformers shared in a substation group. The paper predicts that using probabilistic cost analysis in conjunction to adding spare transformers can be a cost effective way to maintain power to customers."

Data is generated from a 26 single transformer substation group in a non-urban region. Several aging failure model equations are presented, as well as a failure rate function of normal distribution (Figure 1). Table 1 presents substation data, including each individual substation, its in-service year, and its 1998 peak load (MW). Table 2 displays the annual probabilities of the cumulative loss-of-load state for the substation group, including the year, and probabilities for spares 0 through 5. Table 3 displays the savings in damage costs due to adding spares projected for years 1998 through 2017 for the first through fifth spare. Table 4 presents the cash flow for capital investment and damage cost savings projected for years 1998 through 2017, including the capital required and the damage savings predicted.

Search terms and ID: Transformers, Technical, Financial, Journal Article, 92

Light, 1983

Light, B.R.

"Transient Stability Aspects of Power System Reliability (CEGB System)," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September 19-21, 101-104, IEE, London, United Kingdom

Standards for adequate reliability of generation from 400 and 275 kV supergrid networks are discussed. Strategies for designing and operating criteria are presented to ensure that synchronism is maintained under all credible fault conditions. Consequences of stability losses are discussed.

Table 1 presents fault type (single phase to earth, 2 phase, 2 phase to earth, and 3 phase) and rate data are presented for overhead lines, transformers, switchgear, busbars, and cables for 400kV and 275kV systems. Data is from the Central Electricity Generating Board system in the United Kingdom for the 1968 to 1974 period. Data is "to some uncertainty due to incorrect fault diagnosis and/or reporting an also the sampling period considered."

Search terms and ID: Multiple, Data, Technical, Proceedings, 15

Logan, 1994(1)

Logan, D.M.; Billinton, R.

"Value-based transmission resource analysis, Volume 1: technical report," TR-103587-V1, 2878-02, 1994, April, EPRI, Palo Alto, California

Value-based transmission resource analysis (VBRTA) is a comprehensive approach for evaluating the reliability and operating cost impacts of generation and transmission investments and related utility decision on a consistent basis. This report describes a practical framework for implementing VBTRA and demonstrates the framework with a number of case studies. The case studies demonstrate the application of the framework to determining the optimal transfer capability across a particular transmission interface, evaluating specific transmission reinforcements, comparing transmission and generation alternative to serve local area reliability needs, and comparing alternative transmission substation designs. The case studies involve Pacific Gas and Electric Company and Duke Power Company. Chapter 1 provides and introduction. Chapter 2 provides a historical perspective on approaches to this problem. It includes extensive references, 187 citations. Many of these deal with customer outage costs. Chapter 3 describes the VBRTA methodology. It includes descriptions of several software packages that support analyses. Chapter 4 is a case based on the IEEE reliability test system. Chapter 5 presents the utility case studies, and Chapter 6 presents conclusions and recommendations.

In the case studies, a considerable amount of failure data is presented for components. The provenance of the data is not described. The components are transmission level equipment, 115kV and 230kV. Table 5-7 provides data for PG&E. The columns are Contingency, MW unsupplied for 100% load level, Frequency in occurrences per year, and Duration. Tables 5-8 to 5-12 provide the same data for other alternatives. Duke data is provided in Tables 5-19, 5-21, and 5-22.

Search terms and ID: System, Financial, Data, Report, 225

Logan, 1994(2)

Logan, D.M.; Billinton, R.

"Value-based transmission resource analysis, Volume 2:applications guide," TR-103587-V2, 2878-02, 1994, April, EPRI, Palo Alto, California

Value-based transmission resource analysis (VBRTA) is a comprehensive approach for evaluating the reliability and operating cost impacts of generation and transmission investments and related utility decision on a consistent basis. This report describes a practical framework for implementing VBTRA and demonstrates the framework with a number of examples. Chapter 1 summarizes VBTRA principles and approaches. Chapter 2 reviews a number of computer programs that support analysis. Chapter three is the focus of this report and the longest chapter. It provides four brief examples of VBRTA applications including one application to a distribution system.

Search terms and ID: System, Financial, Technical, Report, 226

Longo, 2000

Longo, Vito; Puntel, Walter R.

"Evaluation of Distribution System Enhancements Using Value-Based Reliability Planning Procedures," IEEE Transactions on Power Systems, 2000, August, 15, 3, 1148-1153, IEEE

Value-Based Reliability Planning (VBRP) methods incorporate relative investment, operating costs and reliability valuation, which includes performance during transformer failures and aging from increased stress on remaining transformers. This paper illustrates the application of value-based reliability planning (VBRP) methods to the problem of distribution substation capacity enhancement. The traditional approach is to consider relative investment and operating costs of various alternatives. VBRP enhances the traditional approach with the addition of reliability valuation. This includes a detailed representation of performance during transformer failures and the accelerated aging from increased stress on remaining transformers, as well as the cost of customer interruptions. The addition of a transformer is compared with various distributed resource options, and also the option of doing nothing and incurring more frequent interruptions and greater stress. This paper illustrates the usefulness of VBRP techniques for the planner who must consider customer value in planning decisions. The paper shows how transformers can be reinforced by diesel, battery and DSM reinforcements, thus reducing the percentage of loss of life.

Data presented is from a "typical" substation, so it is not clear if the data is actual or simulated. The key take-away data from the article is displayed in Figure 2, which shows customer damage functions for firm loads and interruptible loads. The graph plots interruption cost ($/kW) versus interruption duration (hours). Figure 3 displays the percentage of transformer loss of life (percentage versus years) for five cases (base case, 3 transformers, diesel units (MTTR = 85 hours), DSM (MW increments) and batteries (% MW for 3 hours).

Search terms and ID: Transformers, Financial, Causes, Journal Article, 97

Lonsdale, 1983

Lonsdale, J.G.; Hitchen, G.B.

"Reliability Evaluation in the Planning of Distribution Systems," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 77-80, IEE, London

This article concentrates on 33/11 kV substations because of the major investments in these systems. Due to the heavy capital investment in substations, systems must be designed to meet precise demand. The authors contend that it is acceptable for automatic load switching at 11kV instead of constructing reinforcing systems. A table is provided that helps assess at which point load switching will be insufficient and system reinforcements will be necessary.

Data is from the National Fault and Interruption Reporting Scheme (NAFIRS). Data table with fault rates for underground cables, overhead lines, transformers, and switchgear. Other tables with calculated data for outage times and corresponding economic consequences.

Search terms and ID: System, Technical, Data, Journal Article, 13

Mackevich, 1990

Mackevich, J.P.; Lynch, D.

"Investigation Into Gas Pressure Generation In New and Aged Aluminum Conductor Cable and the Internal Pressure Withstand Capabilities of Joints, An," IEEE Transactions on Power Delivery, 1990, April, 5, 2

"Water in the strands of electric power cables has been determined to adversely affect service life. In aluminum conductor cable, there can be additional contribution to failure from gas generated by the water-aluminum reaction. This pressure build-up may be substantial resulting in accessory interfacial breakdown and failure due to pressure venting. As a remedy, the industry is exploring various ways to eliminate water in cable by design changes.

The paper reports experimental results on pressure build-up in new and aged aluminum conductor cables. Tests on new cables show that heat is needed to start the reaction. Cables aged for four months were filled with water and heated with induced current to achieve 70° C. After 24 hours of continuous heating the samples all registered some increase in internal pressure but there was considerable variation in the pressure values. The samples were allowed to cool to ambient temperature and reheated to 90° C. While some samples exhibited higher pressure build-up, some other showed lower pressures. This distribution of data indicates that the impact of variables that contribute to pressure build-up has yet to be fully understood.

The paper also tests three joint technologies for internal pressure-withstand capabilities under load with applied voltage. The authors find that heat-shrink technology exhibits the highest withstand capability. Finally, as a section of cable develops pressure, pressure relief and failure will occur at the point of lowest withstand. Failure and outage time can be minimized if the pressure can be contained or else vented by an accessory with easy access. This is an empirical study and has no modeling value for us."

Heat is required to break down the aluminum oxide for the gas reaction to occur.

Search terms and ID: Cables, Causes, Journal Article, 30

Mariton, 1989

Mariton, M.

"On Systems with Non-Markovian Regime Changes," IEEE Transactions on Automatic Control, 1989, March, 34, 3, 346-349, IEEE

A non-Markovian model is proposed for use with a jump model because Markovian models exclude systems with rates dependent on the time elapsed since last transition (typically burn-in and aging phenomena).

A lot of equations are presented in a purely theoretical setting.

Search terms and ID: Non-specific, Equations, Journal Article, 86

Marwali, 1999

Marwali, M.K.C.; Shahidehpour, S. M.

"Probabilistic approach to generation maintenance scheduler with network constraints, A," Electrical power & energy systems, 1999, June 11, 21, 533-545, Elsevier

Presents both a quantitative model and a solution procedure for determining an optimal maintenance schedule for generators. The model considers generator outages and network constraints. The solution uses a decomposition approach based on duality theory. Test results demonstrate that the limits on transmission line capacity affect the loading point of units and increase the generation by expensive and inefficient units.

"Generation oriented.

It would be good to scan the abstract and put that in the summary."

Search terms and ID: Generators, Financial, Technical, Journal Article, 58

Marwali, 1998

Marwali, M.K.C.; Shahidehpour, S.M.

"Long-Term Transmission and Generation Maintenance Scheduling with Network, Fuel and Emission Constraints," IEEE Transactions on Power Systems, 1998, August, 1160-1165

The paper presents an integrated long-term scheduler (LTS) for generating companies (GENCO) with local transmission lines and different constraints. The proposed algorithm extends the Benders decomposition to include network, fuel and emission constraints into LTS. The local network is modeled as a probabilistic problem to include the effect of generation and transmission outages. The approach may be summarized as follows. An objective function is introduced as the sum of maintenance cost of generators, maintenance cost of transmission line, energy production cost, and cost of energy purchased outside. The decision variables are sequences over time that respectively give maintenance status of each unit (binary variables), MBtu of each fuel contract allocated to each unit, and purchased energy. A set of constraints is imposed that reflect maintenance constraints, system emission limits, network constraints (modeled as a transportation model), and fuel constraints. The solution methodology is based on the decomposition of the main problem into the maintenance master problem, operation sub-problem, and fuel dispatch problem. A master problem consisting of maintenance and operation sub-problems (a relaxed problem where minimization is only subject to maintenance constraints, emission limits, and network constraints) is first solved using Benders decomposition. The solution to the master problem is based on relaxing the operation sub-problem constraints and adding appropriate cuts from operation constraints. The solution to the master problem is sent to the fuel dispatch problem that solves for purchased energy, calculates fuel cost, and returns this cost to the master problem. This procedure continues iteratively until no further cost improvement is possible and maintenance schedule satisfies all constraints.

No reference to aging assets.

Search terms and ID: System, Financial, Technical, Journal Article, 32

Matulic, 1990

Matulic, D.; Lubkeman, I.

"Decision Support Approach for Considering Reliability Criteria in the Protective Coordination of Distribution Feeders, A," Electric Power Systems Research Journal, 1990, July, 9, 1, 47 - 56, Elsevier Sequoia

This paper describes an approach for incorporating reliability criteria into the design of protective coordination for distribution feeders. This approach introduces a mechanism for considering the impact of momentary interruptions, caused by excessive switching, upon power quality sensitive loads. The development of a decision support tool for implementing this strategy is also presented. This tool aids the protection engineer by selecting appropriate reclosers and fuses from a component database, checking recloser-to-fuse coordination for all device selections and ranking these selections according to user-selected reliability criteria. An example is included to illustrate the concepts described above.

Search terms and ID: Non-specific, Technical, Financial, Journal Article, 250

Matusheski, 1997

Matusheski, Robert L.

"Predicting success," Power engineering, 1997, February, 101, 2, 26

Discusses the state-of-the-art of predictive maintenance (PDM). Reviews real world applications and measuring the success of real programs. Is focused on generation plants.

Search terms and ID: Generators, Monitoring, Maintenance, Journal Article, 213

May, 1987

May, H.S.

"Revitalisation and Renovation of 66 kV Overhead Lines Within N.E.E.B.," International Conference on Revitalising Transmission and Distribution Systems, 1987, February 25, IEE

"The paper discusses revitalization issues. A distinction has been made between revitalization and maintenance as in the latter case the emphasis is on maintaining what is there while in the former case the emphasis is on equipping the asset for a new lease of life. The paper summarizes renovation requirements for single circuit feeders and double circuit feeders, and discusses single circuit redesign. The paper concludes that renovation of existing overhead line routes can be an economic alternative to rebuilding and raises the possibility of affording improvements in both amenity and expected performance without necessarily increasing costs, through concentration upon structural efficiency.

Suggests that older assets were designed more robustly and were able to maintain a high factor of safety over time, allowing for additional economy of renovation."

A table on page 69 provides failure rates for 66kV and 20kV lines as faults/km. There is note that data is from the National Fault reports, but there is no additional information. Summary of renovation requirements is included for several components of distribution equipment. Focus of the article is poles and supports.

Search terms and ID: Poles, Causes, Data, Journal Article, 39

McCoy, 1978

McCoy, M. F.

"Automated Collection of Transmission Outage Data," 1978 Reliability Conference for the Electric Power Industry, 1978, 16-Nov

As part of a project to provide data and models for a system reliability evaluation program, an extensive analysis of the Bonneville Power Administration's outage data collection activity was performed. The major findings are presented in this paper. Particular emphasis was placed on using existing data and procedures to meet the program requirements. The analysis established that the usefulness of an outage data collection scheme is largely determined by the method of describing and coding outages and the ability to calculate the exposure to important failure modes.

This paper describes the BPA system for data collection. It has a history of its development. It includes many of the codes used for recording data and a copy of its failure reporting form. It does not provide data and is oriented to transmission failures.

Search terms and ID: System, Other, Proceedings, 253

McMahon, 1995

McMahon, B.

"Reliability and Maintenance Practices for Australian and New Zealand HV Transmission Line," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 198-203, IEE, Norwich, UK

Survey of reliability-based maintenance for transmission lines. Description of moving maintenance beyond time-based methods to maintenance based on a mixture of inspection types.

End of paper is mission. Figure 1 presents the age of lines as a function of length. Figure 2 presents data based on the form of line construction (wood, concrete, other steel or galvanized steel). Figure 3 displays the type of maintenance patrols (aerial versus ground). Figure 4 displays the life expectancies of structures. Figure 5 life expectancy of conductors. Figure 6 life expectancy of insulators.

Search terms and ID: Multiple, Maintenance, Data, Proceedings, 78

Medek, 1989

Medek, James D.

"Direct-Buried Primary Cable--The Case for Planned Replacement," Transmission & Distribution, 1989, July, 68-71

"Due to increased URD cable-failure rates, electric utilities have been taking steps to develop cable-replacement programs. The author presents data on estimated URD cable failures from 1985 to 1994. It is found that if underground cable failure rates continue to rise, their planned replacement becomes increasingly important.

The importance of cable replacement programs has begun to show with increased failure rates. However, only six out of approximately 70 utilities surveyed had planned replacement programs.

Cable replacement programs with the greatest success have dedicated staffs that monitor cable failures."

Figure 1 displays a graph of estimated URD cable failures per thousand miles for the years 1985 to 1994. Data was presented for life spans of 24, 26, 28 and 30 years. Table 1 presents the estimated miles of failing cable, showing the miles for 24, 26, 28 and 30-year life cable for the years 1985 through 1994.

Search terms and ID: Cables, Data, Journal Article, 96

Meniconi, 1996

Meniconi, M.; Barry, D.M.

"Power Function Distribution: A Useful and Simple Distribution to Assess Electrical Component Reliability, The," Microelectronic Reliability, 0026-2714, 1996, 36, 9, 1207-1212, Elsevier Science Ltd., UK

Because of its relative simplicity, power functions (exponential distributions) are suggested over complex models like Weibull and lognormal for application in determining component reliability. It may also be more accurate in terms of predicting the stage of a component's life. Application has been tested on EMP data sets.

Several power function equations are presented. The power function is demonstrated for EMP tests on transistors. Curves for reliability and hazard versus time are presented as a case study for differing temperatures.

Search terms and ID: Non-specific, Equations, Technical, Report, 85

Miller, 1995

Miller, George

"Analyzing Transformer Insulating Fluid," EC&M, 1995, November

Insulating fluid is a major component of transformers. Because the oil breaks down in a predictable manner, regular checks can determine trends. Oil tests provide an indication of interior conditions and can prevent unscheduled outages. Several oil tests are listed and described.

Study by Hartford Steam boiler over 20 years indicates that 13% of transformer failures are due to inadequate maintenance. The average failure of these transformers is at 11 years, versus the expected time of 25 to 30 years.

Search terms and ID: Transformers, Monitoring, Journal Article, 22

Mintz, 1990(1)

Mintz, J.D.

"Developments in XLPE-Insulated Underground Distribution Cable," Electricity Today, 1990, April, 2, 3, 30-31

This report examines the status of XLPE-insulated power cables, and the designs of cable installations using XLPE-insulated cables. It uses the information on the life of older cable types and designs and judgment to estimate the expected performance of XLPE-cable and designs. The report was meant to help utility engineers understand developments in cable design, so that they can develop cable standards that would result in the installation of the most appropriate cable. The report describes the basis of the cable life estimates, describes the technical characteristics of XLPE-cable, and presents expected performance of older and XLPE-cable designs.

The report presents data on life in a manner that is unusual and difficult to interpret. Table 2 provides the Approximate Average Age of cable insulated with butyl rubber, high molecular weight PE, and crosslinked polyethylene. Table 3 presents expected effects on cable life of extra clean XLPE improved material handling, improved extruded thermoset shields, processing changes and jackets. In the text the average age seems to be defined as "when failure rates go above 3 faults per year per 100 km" (0.0483 per mile).

Search terms and ID: Cables, Data, Causes, Journal, 256

Mintz, 1990(2)

Mintz, J.D.

"Developments in XLPE-Insulated Underground Distribution Cable - Part II: Options to Current Cable Design," Electrieity Today, 1990, May, 2, 4, 43-46

This report is Part II of an earlier report with the same title. It extends the results of that earlier report. It examines several optional materials and processing changes that at the date of publication (1990) were expected to lengthen the life of XLPE-insulated cable. The author discusses cable specifications, the applicability of traditional qualification tests to the new types of cables, and production testing. The author also provides estimates of the useful life of different new (as of 1990) cable designs.

Table 2 provides the author's estimates of the expected life of different eable designs. Six designs are considered. The designs differ in their use of the following items: full metal barrier, coated foils, swellable powders, encapsulating jacket, purer semi-con material, thure triple extrusion, extruded shields, strand filling, tree retardant material, PE jacket, PVC jacket, Extra clean XLPE, dual tandem extrusion, bonded shield, thicker insulation, super smooth shield, dry cure, salt cure, silane cross linking.

Search terms and ID: Cables, Data, Causes, Journal, 257

Mintz, 1987

Mintz, J.D.

"Survey of experience with polymeric insulated power cable in underground service, Phase III," CEA No. 1117 D 295, 1987, October, CEA, Montreal, Quebec, Canada

Previously, in Phases I and II of this project, data were collected on cable system faults up to 1983. In Phase III, the survey was modified and data were gathered for several more years, up to 1986. Thirty Canadian utilities supplied information on their underground power cable systems. Information available from the U.S. and Europe was used to augment this data. The cable failure rate (excluding dig-ins) over the last 4 years was between 0.9 and 1.3 faults per 100-conductor km per year. American and European rates were less than 0.5. The failure rate from dig-ins was about 0.3 to 0.7. Based on the current installed plant, cable systems with an average age of 10 years have a failure rate of 2 per 100 km per year. With an age of 15, they have a rate of 5 to 6. Accessory faults accounted for 55% of the failures on cable systems. A PC-based computer program was developed to administer the survey and a modified version is available for utilities to keep track of their own cable system reliability.

"Only the title page, abstract, and table of contents for this document are found in the component reliability library. The entire report is available in the EPRI library.

Published in 1986 the data are somewhat dated, but this is an in-depth study. Unfortunately the report does not derive failure or hazard rates with age and it is not straightforward to derive failure or hazard rates with age from the information presented. 28 Canadian utilities contributed data on failure rates. Data covers the period 1977 to 1986. First study (1984) was based on approximately 9500km of XLPE cable. Page 11 gives an average failure rate of 1.13 faults per 100km. with a range from 0.35 to 6.05 faults/ 100km/year with an average cable age of 7 years. Page 13 presents a graph of failure rate with age for cable aged approximately 4 to 19 years. Data are provided for three systems. Table IV, page 14 presents failure rates fro terminations, elbows, and splices from the 1984 Canadian study and an unidentified American study. The next section provides data from non-Canadian sources. Table VI has data from Memphis and Duke for HMPE 175, 240, and 260 mil, XLPE 175, 240, and 260 mil (rows). Data provided are km of cable, kV, kV/mm, 1985 failure rates, 1986 failure rates. Table VII provides Northwest Electric Light and Power Association (NELPA) data. Cable covered (rows) include HMPE 175, 220, 260, 295 mil unjacketed, XLPE 175, 220, 260 mil unjacketed and 175 mil jacketed, tree-retardant HMPE, and tree-retardant XLPE. Data provided are km of cable, kV, kV/mm, number of faults, and failure rate for 1985. Table VIII provides NELPA data for elbows, splices, and terminations. Data provided are kV, number in service, number of failures, and fault rate. Table

IX reports data from an AEIC/EEI survey. Data are for XLPE jacketed in duct <1.6kV/mm, XLPE jacketed in duct >1.6kV/mm, XLPE jacketed direct buried <1.6kV/mm, XLPE jacketed direct buried >1.6kV/mm, XLPE un-jacketed in duct <1.6kV/mm, XLPE un-jacketed in duct >1.6kV/mm, XLPE un-jacketed direct buried <1.6kV/mm, XLPE un-jacketed direct buried >1.6kV/mm, HMPE un-jacketed in duct <1.6kV/mm, HMPE un-jacketed in duct >1.6kV/mm, HMPE un-jacketed direct buried <1.6kV/mm, HMPE un-jacketed direct buried >1.6kV/mm. Table X provides failure rates for various European countries for XLPE, LDPE, and EPR. The countries are Germany, Denmark, France, Ireland, Italy, Netherlands, U.K., Sweden, and Switzerland. Table 12 provides failure rates from France for terminations, splices, and transition joints. Table XIII begins the presentation of the 1984-1986 Canadian data. Rows in this table are years. Columns provide data on km of conductor installed, average cable age, failure rates from dig-ins, other, and total. Table XIII begins the presentation of the data gathered 1978 through 1986. Table XIII lists for each year in that period the km of conductor installed, the average cable age, and the failure rate from dig-in, other and total. Figure 3 graphs this same information. Table XIV shows failure rates for the years 1983 through 1986 by voltage class. Classes are 5, 15 and 25 or 28kV cable. Information is amount in km, average age, and fault rate. Table XV provides failure data for 1983-1986 for PILC cable and Other (mostly Butyl) cable. Information is amount in km, average age, and fault rate. Table XVI provides data on splices, elbows, terminations, and cable-other-dig-in (rows). Data (columns) include number installed, fault rate, conductor length, and fault rate/ 100 km/yr."

Search terms and ID: Cables, Data, Report, 264

Mok, 1996

Mok, Y.L.; Chung, T.S.

"Application of Customer-Interruption Costs for Optimum Distribution Planning," Energy, 1996, 21, 3, 157-164, Elsevier Science Ltd.

"This paper presents a sample application of the value-based distribution reliability planning and modeling methods found in the Billinton material. Eleven alternate capital-improvement projects to a distribution system are compared by total cost, in a total cost minimization. The distribution system reliability modeling formulas using series-parallel reduction with component failure rates and restoration times are the same as those in Billinton's publications, with some simplifications. In addition, the authors use minimal cut-set theory for mesh-distribution systems. This method isn't discussed: the results are just shown. Tabulated values of failure and reliability data for distribution components are used in the reliability modeling. The authors state this type of component data from historical performance is usually available from a utility's database. The average outage rate (f/yr), average annual outage time (hr/yr), average outage duration (hr) are the reliability indices by which alternate plans are compared. Customer interruption costs differentiated by sector, duration, and season are used to calculate the customer cost part of total cost.

Method to determine the reliability cost and worth of the distribution system is presented. The relationship between reliability cost, reliability worth and reliability at the specified load point are obtained, and the optimum system reliability with customer interruptions is determined from the minimum cost to the utility. Uses minimal cut set theory to determine annual customer interruption cost with respect to outages, load and cost of interruption."

Provides reliability data but with no references to source. Table 1 provides data for Busbars, circuit breakers, transformers, fuses, and lines (rows). Data provided include (columns): permanent failure rate (f/year), active failure rate (f/year), repair time (hr), maintenance outage rate (out/yr), Maintenance outage time (hr), switching time (hr), and sticking probability. 80% of unavailability is associated with 11 kV distribution systems. Consumer-interruption cost is difficult to calculate because it is dependent upon consumers' perception of worth of interruption.

Search terms and ID: Multiple, Data, Financial, Journal Article, 46

Moravek, 1994

Moravek, James

"Benefits of using a harmonic monitoring program," Electrical Construction & Maintenance, 1994, September, Intertec

The proactive approach to harmonics is to monitor loads on equipment susceptible to harmonics. Monitoring consists of two parts; establish a baseline reading to determine if the tested equipment is operating within its stated parameters, if not, take corrective actions. If the equipment is operating within its parameters, we should evaluate the loading to determine what derating should be applied when adding future loads. The author recommends the following equipment to be monitored for harmonics: transformers, power distribution units, neutrals for feeders and branch circuits, UPS systems, emergency power generator used in conjunction with UPS systems or other significant nonlinear loads, capacitors, circuit breakers. The paper gives some derating guidelines.

Recommends a monitoring program to assist in identifying problems caused by harmonics.

Harmonics can cause:

-Overheating of electromagnetic equipment and neutral conductors

-Malfunctioning of control systems dependent on wave-form

Equipment to monitor for harmonics includes: transformers, power distribution units, neutrals for feeders and brand circuits, UPS systems, Emergency power generator sets, capacitors, circuit breakers.

Search terms and ID: Multiple, Monitoring, Causes, Journal Article, 57

Muir, 2000

Muir, Fiona

"1999/2000 Quality of Supply Report," NM396, 2000, 28-Jun, Scottish Power

Report summarizes the quality of supply to customers in the Wales, Merseyside and Cheshire areas. Descriptions of system failures due to mechanical and natural forces are described simply for system customers.

There are a lot of general information data tables, but not a lot of failure data. Table 2 (page 20) provided fault distribution data for low voltage and high voltage overhead, underground and other cables.

Search terms and ID: System, Data, Report, 125

Nelson, 1998

Nelson, R.F.

"Reliability-centered power line management - inspection process, measurement techniques and data management considerations," Colloquium on Distribution overhead lines - economics, practice, and technology of reliability assessment, 1998, 289, 3/1 - 3/24, IEE, London, UK

While methods and practices for maintaining the reliability of overhead line systems may differ between US and UK electric utilities, there are more similarities than differences. Impending deregulation has forced more immediate changes within the industry to evaluate current design and maintenance practices to achieve the most from available assets at the least cost. As utility line managers desire more quantitative inspection information by which to optimize required maintenance and forecast line performance and maintenance needs, line inspectors are required to utilize state-of-the-art tools and techniques capable of providing such information. The intent of this paper is to review tools and techniques, which can enhance the data, obtained during the inspection process for overhead wood pole lines. The ability to consistently collect and report quantitative data is a critical component of the Reliability-Centered Management (RCM) approach to overhead line management.

Provides several graphs indicating the accuracy of various tests in predicting MORGL, MORBP, and Tip Load. Since none of these terms are defined accurately in the text the usefulness of these relationships is hard to judge.

Search terms and ID: Poles, Monitoring, Proceedings, 242

Ngundam, 1983

Ngundam, J.M.; Short, M.J.

"Prediction of Circuit Breaker Reliability," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 137-144, IEE, London, United Kingdom

This paper contends that better reliability can be achieved by better design and production and by the use of better materials. Reliability is as dependent on the material dielectric and mechanical properties of components as on the operating conditions. The author models failures within a circuit to determine the probability of the circuit breaker being activated, and from this the probability of circuit breaker deterioration and failure. Deterioration reduced circuit breaker reliability at each stage. The article also suggests that components can remain economically feasible if regularly maintained. System reliability is dependent on assessing component deterioration.

In Table 4 fault data is provided for overhead lines, transformers, switchgear, and cables (rows) for varying fault types. Fault rates (columns) are provided for 400kV and 275kV. Charts of reliability versus time integrate data such as the number of faults, location of faults, and line length are presented. Data is from 1968 through 1974 from the CEGB.

Search terms and ID: Multiple, Data, Technical, Journal Article, 9

Patton, 1968

Patton, Alton D.

"Determination and Analysis of Data for Reliability Studies," IEEE Transactions on Power Apparatus and Systems, 1968, January, PAS-87, 1, 84-100, IEEE

Paper discusses estimating required component parameters from field data. Field data can be used to estimate component outage rates and mean outage durations. The estimated component parameters can then be used in reliability analyses. Confidence levels and conditions for pooling data between companies are also presented.

Several regression equations associated with the analysis are presented. Figure 2 displays lightning-caused transient-caused forced outages of unshielded, single-pole 69-kV transmission lines. Table I Displays regression analysis results for transmission line outage rates for transient-cause forced outages (lightning and nonlightning), persistent-cause forced outages and scheduled outages. Figure 3 displays distribution of time periods between transient-cause forced outages and scheduled outages. Figure 4 presents distributions of persistent-cause forced outage durations for 69-kV transmission lines. Figure 5 presents the distribution of scheduled outage durations for shielded H-frame 69-kV transmission lines. Table II lists transmission line outage duration statistics for persistent-cause forced and scheduled outages. Figure 6 presents the distribution of time periods between scheduled outages of a 138/12.5 kV, 20 MVA, FA substation transformer. Tables IV and V display substation component forced and scheduled outage rates for various voltage transformers, circuit breakers, buses and air switches. Figure 7 displays the distribution of persistent-cause forced outage durations for 69-kV distribution substation transformers. Figure 8 presents the distribution of 69-kV transmission manual switching times and transformer fuse replacement times. Table VII presents substation component persistent forced outage duration and switching time statistics for transformers, circuit breakers, buses, air switches, annual switches and fuses. Table VIII displays substation component scheduled outage duration statistics for transformers, circuit breakers buses and air switches. In the discussion portion of the paper, Figures 9 and 10 present outage per year versus line exposure distance prediction lines with confidence limits. Figure 11 displays data comparing outages per year per mile versus line exposure distance.

Search terms and ID: System, Data, Journal Article, 118

Paulson, 1966

Paulson, N. L.; Carey, W. L.

"Outage Analysis Spots Trouble Areas," Electrical World, 1966, 21-Mar, 88-89, 153, McGraw-Hill

Paper discusses how outage reporting has evolved into a company-wide procedure for Portland General Electric.

Only data from 1964 is presented: Underground direct-buried primary cable circuits have one-fifth the failure rate per circuit-mile of overhead primary circuits. Underground secondary system, including distribution transformers, has one-tenth the customer outage frequency rate of the overhead secondary system. Dig-ins, resulting in cable failures, are the major cause of outage to the underground system. Average customer outage duration is nearly three times as long for an underground system as for an overhead system.

Search terms and ID: System, Monitoring, Journal Article, 105

Payne, 1995

Payne, K.G.; Brown, L.S.

"Prioritizing Supply Infrastructure Works Using Statistically Based Analyses," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 157-161, IEE, Norwich, UK

Statistical model to predict deterioration so that a defined failure can be predicted, consequences understood, and corresponding losses calculated. Illustrates reliability analyses using fault trees.

Paper is exclusively qualitative, providing models for yes/no decisions regarding prioritizing power equipment replacement investments. Case study of power distribution's role in the operation of the London Underground.

Search terms and ID: System, Financial, Technical, Proceedings, 73

Peelo, 1996

Peelo, D.F.; Meehan, J.; Bergman, W.J.

"On-line condition monitoring of substation power equipment utility needs," CEA No. 485 T 1049, 1996, December, Canadian Electricity Association, Montreal, Quebec

The report examines the application of substation equipment on-line condition monitoring form a utility perspective. Equipment failure and outage statistics are examined. Equipment attributes that could be monitored and the derived value are listed. The basic conclusion of the report is that equipment on-line condition monitoring can provide needed and justifiable value if applied in the broad context of achieving predictive maintenance and improved equipment utilization, functionality and life management

We do not have the whole report. Only the executive summary, conclusions, recommendations, and references. We should attempt to obtain the whole report.

Search terms and ID: Multiple, Monitoring, Report, 51

Philipson, 1992

Philipson, Lorrin

"Maintaining reliability," Electrical world, 1992, June 1, 15, McGraw-Hill

Discusses the approaches taken to distribution system maintenance at several utilities. Overall theme is strategies for dealing with reduced budgets and other constraints while maintaining reliability. Suggests that many utilities are so reluctant to make capital investments that they are not making distribution system investments with payback periods as low as 3 years.

Search terms and ID: Multiple, Maintenance, Monitoring, Journal Article, 217

Power System Engineering Committee, 1973

Power System Engineering Committee

"IEEE Standard Definitions in Power Operations Terminology including terms for reporting and analyzing outages of electrical transmission and distribution facilities and interruptions to customer service," Std 346-1973, 1973, 12-Nov, IEEE

Supplies definitions for terms associated with component outages and service interruptions.

Search terms and ID: Other, Other, Report, 268

Procaccia, 1997

Procaccia, H.; Cordier, R.; Muller, S.

"Application of Bayesian statistical decision theory for maintenance optimization problem," Reliability Engineering and System Safety, 0951-8320, 1997, 55, 143-149, Elsevier Science Ltd., Northern Ireland

A Bayesian approach, combined with operating feedback, risk consequences and economic consequences, can be used to determine optimized Reliability-Centered Maintenance (RCM) policies. This method is proposed for instances where 1) there is little operating feedback concerning rare events affecting a critical piece of equipment, and 2) when the goal is to optimize the maintenance frequency of critical equipment. Use of feedback from observations is limited because, as the paper contends, Bayesian modeling is suited for the evaluation of probabilities in an uncertain space. Paper discusses diesel engines at nuclear power plants.

Some observations are presented for which the model is compared to. The observations include yes or no answers to a question of the probability of a scratch occurring in block linings of a diesel engine over a certain operating time. The types of scratches considered are nicks, short scratches, long scratches, short deep scratches, long deep scratches, and scratches entailing oil leak or excess crankcase pressure. A model is used to present a graph establishing a law of failure versus the number of starts. A decision tree is also presented with anecdotal data.

Search terms and ID: Other, Technical, Monitoring, Journal Article, 82

Pryor, 1987

Pryor, B.M.

"Factors affecting the deterioration of HV switchgear," Revitalising transmission and distribution systems, 1987, February 25-27, 273, 92-97, IEE, London, United Kingdom

"A mainly qualitative description of the factors affecting the deterioration of HV switchgear. Suggests that for equipment over 25 years of age where other test methods are not available select units should be taken out of service, disassembled, and thoroughly inspected.

The paper discusses factors that affect the deterioration of HV switchgear. These factors are operational/design features, fault rating and switching conditions, thermal limitations, age, maintenance requirements, environmental aspects, dielectric considerations and spares availability."

Discusses voltage range from 3.3 to 420 kV plain-brake circuit-breakers. Typical problems found are:

- Obsolescence in design
- Fault levels beyond capability
- Use other disconnector
- Fitted with dependent manual operating mechanism
- Not properly grounded

Major thermal deterioration problems are associated with outdoor distribution and transmission equipment where oxidation of external joint faces can occur.

Search terms and ID: Switches, Monitoring, Causes, Proceedings, 53

Pugh, 1997

Pugh, J.S.; Castro Ferreira, L.R. ; Crossley, P.A.; Allan, R.N.; Goody, J.; Downes, J.

"Reliability of Protection and Control Systems for Transmission Feeders, The," Development in Power System Protection, 1997, March 25, 434, IEE

"This paper introduces a technique for assessing the reliability of protection and control systems using reliability models and event tree analysis. An event tree provides a visual way for calculating the probability of a sequence of events given single event probabilities. This technique allows a quantitative assessment of dependability (the probability that the protection operates satisfactorily when required) and security (the probability that the protection does not operate when not required) to be made. These assessments can then be used to determine the effect of integrating different protection and control functions into a single unit.

The paper presents dependability results for feeder protection schemes based on differential protection and distance protection and combined differential and distance protection. The paper also considers the effect on the dependability of these schemes of including a separate and an integral inter-trip. It is worth noting that the model is static, so that there is no change in event probabilities due to aging or wear.

Combining functions into a single unit can have a degrading effect on reliability due to the increased risk of common mode failures."

Page 12 provides what is characterized as illustrative data on failure rates for several components. The components include power supply unit, communications links, intertrips, digital outputs, and others. The author uses abbreviations for components and without more understanding of these systems component identification is uncertain.

Search terms and ID: System, Technical, Data, Journal Article, 38

Radtke, 1991

Radtke, Michael I.

"Failure Analysis Improves Distribution Transformer Quality," Transmission & Distribution, 1991, November, 82-86

Wisconsin Public Service Corp. (WPS) Green Bay, WI, serves more than 320000 electric customers in a 10000 sq mi area of Northeastern Wisconsin. During the 1970's WPS kept transformer failure and repair data and suspected marked differences between manufacturers. However, the company had no formal way of analyzing the data. During the mid 1980s, WPS developed a formal transformer failure analysis program. The program was initiated so that WPS could measure the reliability of individual manufacturers, develop accurate failure costs, and improve communications between transformer manufacturers and users. The author describes how WPS has found significant failure rate reductions during the 5 yr of formal failure analysis. For 10 and 15 kV single-phase overhead units, they have seen a 33% reduction in failure rate from an average of 1.09 for the 1983-through-1986 period to 0.73 for the 1987-90 period.

The paper presents hazard rate and failure rate data. Hazard rate is defined as the number of failures in a year divided by the number of units in service at the beginning of the year. Failure rate is defined as the total number of failures divided by the total unit years of service. Figures 4 and 5 display the failure rate for 10-15 kVA overhead transformers and 25-250 kVA overhead transformers, respectively, for varying manufacturers. Figure 6 displays the transformer failure rate for single-phase pad-mounted transformers for varying manufacturers. Figures 7 and 8 display transformer failure analysis for 10 kVA and 25 kVA, respectively, overhead transformers from 1987 to 1990 by comparing failure cost adder dollars versus manufacturers.

Search terms and ID: Transformers, Data, Journal Article, 95

Reder, 2000

Reder, W.; Flaten, D.

"Reliability centered maintenance for distribution underground systems," 2000 Power Engineering Society Summer Meeting, 2000, 1, 551-556, IEEE, Piscataway, NJ

With the technical advent of predictive testing for electric distribution facilities, reliability centered maintenance (RCM) principles can now be applied to maintain underground systems. This paper reviews the history and concepts of RCM, discusses the typical RCM underground process, identifies technical steps for applying RCM to manage distribution underground cable, and discusses the benefits along with the key success factors for managing underground facilities in this fashion. Finally, a case study is discussed demonstrating the application and results of RCM for distribution underground systems.

Suggest that testing can significantly increase the effectiveness of cable replacement programs. Used Ultra Power Technologies Inc. cable testing, but provides no further information on the test performed.

Search terms and ID: System, Financial, Maintenance, Proceedings, 237

Reinhart, 1997

Reinhart, Eugene R.

"Keeping power plants profitable," Mechanical engineering-CIME, 1997, April, 119, 4, 74

Discusses advances in nondestructive evaluation of generator components such as turbine blades, turbine rotors, and pipes. Considers how these tests can improve maintenance procedures.

Search terms and ID: Generators, Monitoring, Maintenance, Journal Article, 207

Renforth, 1998

Renforth, L.

"Economic case for reliability centred maintenance in the UK - a pilot study," Colloquium on Distribution overhead lines - economics, practice, and technology of reliability assessment, 1998, 289, 5/1 - 5/5, IEE, London, UK

The purpose of the pilot project was to demonstrate the application of inspection techniques and assessment methodologies aimed at improving the quality of field data to enable sound maintenance decisions to be made regarding wood pole OH lines. Reliability-Centred Power Line Management, which encompasses practical use of inspection technologies and assessment methods, has proven to result in very favourable cost-benefit ratios in the US. The pilot project applied an inspection and assessment approach such that the REC could identify the applicability of RCM to the management of their overhead lines. Whilst various levels of assessment methodology are possible any solution must consider the cost benefit of extending service life using RCM in both the short and the long term. In order to compare the maintenance options a life-cycle cost analysis has been carried out to compare the options (rebuild, selective repair, selective replacement etc) over a 20-year cycle by applying the concept of Net Present Value.

Some data is provided on the cost of inspections, pole repairs, and pole replacement in the UK.

Search terms and ID: Poles, Monitoring, Proceedings, 244

Rhoten, 1971

Rhoten, G. P.

"Evaluation of Service Reliability," 1971, 1-6, IEEE

Paper discusses a system implemented in Texas in the late 1950s that processes service interruptions as the basis for reliability evaluation.

Some data is presented, but only to highlight a point. Source of data is unknown.

Search terms and ID: System, Data, Journal Article, 102

Rhoten, 1961

Rhoten, G. P.

"General Program for Processing Distribution Data, A (Orients Distribution Computer Data)," Electrical World, 1961, Dec. 18, 45-48, 126, McGraw-Hill

Paper discusses the location, accumulation, processing and monitoring of interruption data from a 1,000,000-foot square area grid. A computer is used to process information regarding distribution property, equipment or customer located on the grid.

Paper presents no aging asset data and does not lend itself to this study.

Search terms and ID: System, Monitoring, Journal Article, 104

Roberts, Jr., 1993

Roberts, Jr., W.T.; Mann, Jr., L.

"Failure Predictions in Repairable Multi-Component Systems," International journal of production economics, 1993, 29, 103-110, Elsevier

Authors discuss that multi-component repairable systems cannot be modeled by continuous distributions, such as the Weibull. Nonhomogenous Poisson Process (NHPP) models are recognized as better representing repairable systems. Since most systems are repaired, not replaced, NHPP are better. The objective is to prove that a simulation based on Weibull parameters of major components is able to duplicate the NHPP model. The simulations can provide failure prediction results that can be traced to individual components. The simulation can identify a finite number of parts that contribute to the overall system downtime and this information can guide maintenance.

System components for which failure data is provided are not identified. Data charts are presented that display reliability versus time for both NHPP and Weibull.

Search terms and ID: System, Technical, Journal Article, 27

Robertson, 1998

Robertson, C.

"Inspection & data collection procedures - present & future," Colloquium on Distribution overhead lines - economics, practice, and technology of reliability assessment, 1998, 289, 4/1 - 4/14, IEE, London, UK

Discusses inspection and maintenance responsibilities under UK regulations. Describes a typical current inspection program for a hypothetical set of poles. Provides a typical inspection questionnaire.

Search terms and ID: Poles, Monitoring, Proceedings, 243

Saddock, 1976

Saddock, H. G.; Bhavaraju, M. P.; Billinton, R.; DeSieno, C. F.; Endrenyi, J.; Jorgensen, G. E.

"Common Mode Forced Outages of Overhead Transmission Lines," IEEE Transactions on Power Apparatus and Systems, 1976, May/June, PAS-95, 3, 859-863, IEEE

As more transmission lines are constructed in already occupied right-of-way, this paper posits that there is a need for definition and data collection of common mode outages of multiple transmission lines. This paper outlines a method for reporting of common mode outages of multiple transmission lines, and presents indices of common mode outages and methods for calculating said indices.

No real data is presented. Paper presents suggested report forms for recording common mode outages of multiple transmission lines. Sample data and calculations are presented.

Search terms and ID: Cables, Data, Journal Article, 115

Sakai, 1983

Sakai, Takami; Kumamaru, Toshio ; Sugawara, M. ; Sasagawa, H.

"Development of the Computing Program for the Reliability Evaluation of Equipment," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 127-131, IEE, London, United Kingdom

This article discusses a computing program (TOSPEC) for analyzing the probability of failure of a system. It has such features as not requiring fault trees or event trees according to schematic diagrams; it can evaluate the effect of failure of each component; it can calculate reliability and availability; and it can calculate minimal cut set.

The article contains analytical diagrams for the probability of failure and a diagram displaying the sensitivity of failure probability to the interval of automatic testing.

Search terms and ID: System, Technical, Proceedings, 7

Salis, 1999

Salis, G.J.; Safigianni, A.S.

"Long-Term Optimization of Radial Primary Distribution Networks by Conductor Replacements," Electrical Power and Energy Systems 21 (1998), 1999, 21, 349-355, Elsevier Science Ltd.

The optimum planning of power distribution networks is important because these networks are close to customers and are characterized by high investment and operational cost. This paper develops a method for technoeconomical long-term optimization of currently operating radial primary power distribution networks. The method utilizes results and suitably modifies computational procedures described earlier in the literature. The method identifies the optimal (least cost) timing and location of conductor replacements at the network segments so that the network may approximate its long-term optimum form. The method takes into account the realistic locations and growth of the load served by the examined network and specific technoeconomical constraints.

For each conductor in a network segment, the total cost of losses is calculated as the net present worth of annual losses (over the planning horizon) per unit length of the segment, assuming constant losses beyond a pre-specified period within the plan horizon. Defining cost as total loss plus operational costs per unit length for the component of interest, the decision function is defined as the difference between two cost functions that correspond to the component and its upgrade.

A so-called "long term" algorithm based on the above defined decision function is proposed that accounts for technical constraints related to power flow in the network segments, thermal short-circuit strength of the conductors, and conductor tapering in the network segments. The algorithm also examines the network voltage profile. Since the replacement proposals are sequential, upon termination of the long term optimization routine, the algorithm runs scenarios that examine the improvement of the economical results for the proposed replacements being executed earlier than the years calculated by the long term (sequential) optimization routine.

The technique is applied to a feeder of the primary power distribution network of the area of Xanthi, Greece. This appears to be a straightforward decision problem and the modeling is elementary. There is nothing interesting here about aging assets, and the main issue is mitigating losses.

Final economic results found that profits from the savings in reduced losses more than compensated for the system's required investment."

Optimum selection is closest to the optimum that satisfies specific technical constraints with the minimal possible cost.

Search terms and ID: System, Financial, Technical, Journal Article, 33

Sanwarwalla, 1995

Sanwarwalla, Mansoor; Weinacht, Rick

Aging Management Through Condition Monitoring of ASCo Solenoid Valves and NAMCO Switches," Plant Systems/Components Aging Management, 1995, 316, 51-57, ASME

This paper advocates that periodic replacement costs of ASCo solenoid valves and NAMCO limit switches can be decreased by controlling aging through baseline characteristic/performance criteria and periodic condition monitoring. These processes allow for the optimization of the qualified life of the components, reducing the replacement frequency, and thus equipment replacement and maintenance costs. The components are used in nuclear power plants.

Material properties of the equipment and a summary test plan are presented. No aging data is presented.

Search terms and ID: Other, Causes, Journal Article, 81

Schimmoller, 1998

Schimmoller, Brian K.

"Shake those Boeing blues," Power engineering, 1998, September, 102, 9, 12

Briefly describes the reliability centered maintenance (RCM) program at TVA's Cumberland Fossil Plant

Search terms and ID: Generators, Maintenance, Journal Article, 208

Serwinowski, 1997

Serwinowski, Mark A.; Hatch, David C.

"Prudent Management of Utility Assets—Problem or Promise?," 1997, 475-478

Paper discusses strategies to improve asset management by way of Economic Value Added (EVA). EVA focuses on increasing positive cash flows and minimizing negative cash flows. Tools that can be used to increase EVA include value-added engineering, remedial strategies, market valuation strategies, best use analyses, etc. EVA helps reach decisions regarding improving, selling, or deferring assets. Improving EVA as part of total asset management helps maximize capital resources, reduce operating expenses, increase financial returns and improve intangibles like corporate image.

Aging assets not explicitly discussed. General framework for use of EVA presented.

Search terms and ID: Non-specific, Financial, Report, 37

Settembrini, 1991

Settembrini, R.C.; Fisher, J.R. ; Hudak, N.E.

"Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, Dallas, 1991, September, 704-712, IEEE

Seven common distribution systems (simple radial, primary auto loop, underground residential distribution, primary selective, secondary selective, distributed grid network, spot network) were analyzed by comparing field performance and theoretical calculations for frequency and average duration of outages. Distribution systems were then ranked by reliability and ability to deliver "clean power." The selection criteria enable distribution engineers to choose a system of reliable power based upon customer needs. Reliability is compared by the number of outages per year;

average duration of the outage; number of momentary interruptions per year; power quality; voltage regulation; and voltage disturbances.

Failures per year and average downtime per failure for primary feeders, transformers, and secondary line are presented. No source is cited. The seven distribution systems analyzed are 1) Simple Radial; 2) Primary Auto Loop; 3) Underground Residential; 4) Primary Selective; 5) Secondary Selective; 6) Distributed Grid Network; and 7) Spot Network. Grid Networks were found to be the most reliable.

Search terms and ID: System, Technical, Data, Journal Article, 50

Settje, 1996

Settje, Scott

"Transformer Reliability: Some Considerations as Presented by Loss History," PWR Volume 30 Joint Power Generation Conference, Vol 2, 1996, 30, 257-263, ASME

"This paper argues that even though the reliability of transformers in North America, measured by Mean Time Between Failures (MTBF), is extremely good, it is important to examine the impact that a loss can have on the individual producer or user to gain insight into the economics of transformer failure. The paper argues that the multiple competitive alternatives in front of consumers could drive the cost cutting of the suppliers to a point where reliability and maintenance suffer. In the future, the paper continues, the power generation, transmission and other players will not carry the cost of spare transformers, and will depend more upon long life and reliability of single unit systems. If a supplier does not meet contractual agreements, the customer will have the option of seeking new suppliers and that will be a double blow to the less reliable supplier. This makes the issue of reliability versus cost cutting a very delicate matter. The paper then provides life expectancy curve of a transformer (life expectancy in hours versus the average temperature within which it operates) and the deteriorating effect of usage (curves that describe projected loss of life as a result of operating the transformer at temperatures above its nominal value for different number of hours). Looking at loss history, the paper concludes that loss frequency is highest for transformers in the 16-25 years old brackets and when the cost per occurrence is broken down, it is found that the resulting graph follows a typical bathtub curve. Utility transformer losses do not display the same costs per occurrence as industrial units due to the way the underlying insurance is purchased.

The paper further argues that in the future the utilities may need to purchase business interruption insurance to help supplement a less reliable generating or distribution system. The paper finally concludes that the preplanning and the application of a sound inspection and testing program will help reduce the frequency and mitigate the severity of failures since the result of a loss and the recovery is usually much higher than expected.

Article discusses common methods that utility and industrial users and owners can employ in a reliability program. Several graphs are presented that express life expectancy as a function of temperature, maximum loss of life curves that include penalties for operating under high temperatures, data tables for transformer losses, and a table for utility transformer losses by size."

Figure 1 provides life expectancy curve of a transformer (life expectancy in hours versus the average temperature within which it operates) and the deteriorating effect of usage (curves that describe projected loss of life as a result of operating the transformer at temperatures above its nominal value for different number of hours).

Table 1 provides numbers of losses for transformer with different years in service. Unfortunately sample sizes are not provided. Data is for the years 1985-1995. The data source is assumed to Arkwright Mutual Insurance, the affiliation of the author. Though this is not stated in the text.

Author states that transformers in North America are extremely reliable, but even small interruptions cause large problems and cost as much as $1 million per day. Costs dictate having reliability with out redundancy. Losses have differing costs for industrial units due to insurance purchasing programs. Loss of life is cumulative. Most transformer losses occur when transformers are 16 to 25 years old, but the highest rate of loss occurs when transformers have 1 to 5 and 36 to 40 years of service."

Search terms and ID: Transformers, Financial, Maintenance, Proceedings, 19

Sim, 1988

Sim, S.H.; Endrenyi, J.

"Optimal Preventive Maintenance witb Repair," IEEE Transactions on Reliability, 1988, 92-96, IEEE

The paper develops a minimal preventive-maintenance model for repairable continuously operating devices whose conditions deteriorate with the time in service. The main ingredients of the model are as follows. The device is susceptible to two types of failure, namely, deterioration and Poisson. The device has a deterioration failure immediately following the completion of k stages of deterioration. The device is periodically removed from operation for minimal preventive-maintenance and this moves the device one stage back in its deterioration process. The device has also a Poisson failure, which occurs at the same constant rate in any of the deterioration stages, and this implies exponentially distributed times to failure for the Poisson failures. Moreover, the duration of each stage in the deterioration process is distributed according to a common exponential distribution. In addition to the deterioration process, the device goes through a minimal preventive-maintenance process for which the times to preventive-maintenance are distributed according to an Erlang distribution.

Defining tbe state as the stage in the deterioration process and tbe stage in the maintenance process, the paper presents steady-state equations for state transition probabilities as a set of

algebraic equations. For the special case where there is only one stage in the preventive maintenance process, the paper presents an algorithm for sequential calculation of probabilities. For the general case, the paper calculates the mean time to preventive maintenance that minimizes the unavailability of the device defined as the sum of probabilities of unavailability due to Poisson and deterioration failures and unavailability due to preventive maintenance.

A model is presented that aims to minimize unavailability due to preventative maintenance, Poisson-distributed failures and deterioration failures. A Markov model is broken into stages where times to preventative maintenance use an Erlang distribution. Because Poisson failures cannot be prevented by preventative maintenance (PM), as the proportion of Poisson failures increases, the need for minimal PM decreases. The optimal time to minimal maintenance decreases as the mean repair time for deteriorating failures increases. As the Erlang parameter increases, the minimum availability decreases."

Search terms and ID: Non-specific, Financial, Technical, Journal Article, 36

Srinivasan, 1984

Srinivasan, N.; Prakasa, K.S. ; Indulkar, C.S.

"Novel Method for Filtering and Ranking of Critical Contingencies, A," Electrical Machines and Power Systems 1984, 1984, 9, 359-374, Hemisphere Publishing Corporation

New method that uses a line outage simulation technique to compute the new state of the system using a constant sensitivity matrix. Infinite norm is used to filter and rank critical contingencies. This new method uses no more computing power that previous methods. Additionally, this method provides a complete picture of the system with regards to line overloads, voltage levels and reactive power generations, as well as the value performance index under a contingency.

Provides a system scenario including bus voltages, angles, line flows and reactive power generations, along with the values of the performance indices following an outage.

Search terms and ID: System, Technical, Journal Article, 35

Stahlkopf, 1995

Stahlkopf, Karl

"Advanced maintenance technology improves power delivery systems," Electric light & power, 1995, June, 73, 6, 32

Discusses the growing application of reliability-centered maintenance (RCM), in particular EPRI's efforts in this area. The paper goes into some detail on new devices that support maintenance programs.

Search terms and ID: System, Maintenance, Journal Article, 210

Steed, 1995

Steed, John C.

"RTDE '95 - The Importance of Equipment Reliability," Power engineering journal, 1995, June, 142-144

Summary of RTDE '95 conference, where consideration for equipment performance emerged as an aim. Topics discussed include methods of diagnosing reliability and plant failure statistics; design for reliability; condition monitoring; methods for improving distribution system reliability; and asset management. Some theories regarding predictive tools are now being questioned.

Cellulosic degradation byproducts provide a clue for fault and/or aging conditions. Furfuraldhyde is a product of paper aging found in insulating oil in certain high-temperature situations.

Search terms and ID: Non-specific, Other, Journal Article, 42

Steed, 1994

Steed, J.C.

"Experiences With Power Transformers in Southern Electric," IEE Colloquium (Digest), 1994, 075, 3/1-3/6, IEE, London, United Kingdom

"The normally quiescent state of electrical transmission and distribution system plant does not draw attention to incipient faults, which may develop from the gradual deterioration of the equipment. These faults may be detected during routine maintenance but the ability to have detailed information on the state-of-health of transmission and distribution system equipment prior to carrying out maintenance work or alterations becomes a significant asset and adds an element of preventive maintenance to the operation of such assets.

The initial stage of condition monitoring consists of establishing the baseline parameters and recording the actual base line values. The next stage is to determine trends by observing the running condition and assessing the parameters previously determined for the baseline. The state of the present plant conditions can be obtained from the absolute figures and the rate of degradation can be estimated from the trend.

The benefits of condition monitoring can be summarized as reduced maintenance costs, quality control features provided by the results, limiting the probability of destructive failures, limiting the severity of any damage incurred and information provided on the transformer operating life. This information may enable business decisions to be made either on plant refurbishment or on asset replacement.

As transformers are generally extremely reliable, condition monitoring is usually performed on associated equipment such as on-load tap-changers. The paper mentions some of the techniques available to the user for monitoring the condition of power transformers. The topics (briefly) reviewed in this connection include oil analysis survey, winding movement detection, asset replacement survey, condition monitoring and asset replacement, and condition monitoring research. The paper concludes that condition monitoring must not be a purely scientific activity driven by technology but a maintenance approach driven by financial, operational, and safety requirements. It must provide information on plant condition to allow maintenance resources to be optimized and assist with the optimum economic replacement of the asset. No methodology is developed in this paper.

Case history of preventative maintenance based on establishing baseline parameters, recording the actual baseline, determining trends, and then determining the rate of degradation. Condition monitoring research can use fault statistics to monitor equipment failure rates and predict equipment lifetimes. It is also useful to conduct post-mortems to determine mechanisms of failure and to show multiple modes of failure. Types of condition monitoring discussed are oil analysis surveys, winding movement detection, and condition assessments. The author also states that there is a distinct difference between nameplate age and the insulation age in assessing transformer life."

Paper discusses preventative maintenance in predicting failures, but the paper does not discuss the failures themselves. Presents a condition assessment for power transformers that includes assessments of insulation systems, corrosion, general condition, and operation (reliability, availability of spares). Notes that for Southern the failure rate for h.v./l.v. ground mounted transformers is below 0.2% on a population of around 25,000.

Search terms and ID: Transformers, Monitoring, Data, Proceedings, 18

Steed, 1986

Steed, J.C.

"Using Fault Statistics to Monitor Equipment Failure Rates and Lifetimes," Revitalising Transmission and Distribution Systems, 1986, February 25-27, 273, 15-20, IEE, London, United Kingdom

The paper presents a national (UK) analysis of faults and illustrates some equipment aging failure rates and attempts to provide further information on plant lifetimes. For different components, the paper calculates hazard rate curves (the so-called bathtub curve, which plots hazard rate or the rate of occurrence of failures versus the age of the component). In doing so, some assumptions are made, among others, that system is non-repairable (each failure is replaced). The paper then studies the applicability of these assumptions to overhead lines, underground cables, pole-mounted transformers, ground mounted transformers, and HV switchgear, and calculates hazard rate curves when appropriate.

Article presents 20 years of data with 57 different direct cause categories. Faults are analyzed to illustrate equipment failure rates due to aging and plant lifetimes. Data is presented displaying aging failures and other failures versus time for systems of varying voltages. The article differentiates between failure rates and hazard rates. Hazard rates account for surviving equipment as well as failed equipment. Hazard rates are highest for equipment at the earliest and latest ages, creating a ""bath tub"" curve for Hazard rates versus age. Specific data is presented for varying cables, pole-mounted transformers, ground-mounted transformers, and switchgear. Aging should also be considered in conjunction of unacceptable failure rates, obsolescence, safety, etc.

Figure 1 plots number or fault reports (3 year moving average) for the low voltage (below 1kV system) versus year for deterioration due to aging and other direct causes.

Figure 2 plots number or fault reports (3 year moving average) for the low voltage (below 1kV system) versus year for overhead lines, underground cables, switchgear and fuses.

Figure 3 plots number or fault reports (3 year moving average) for the greater than 1kV and not exceeding 20kV, the 33kV and 66kV, and combined versus year for overhead lines and underground cables.

Figure 5 plots fault rate (3year moving average) per 100km versus year for 11kV cable.

Figure 6 plots %equal to or less than age shown versus age for pole-mounted transformers for 1985-1986.

Figure 7plots the hazard rate versus age of pole mounted transformers for 1985 -1986.

Figure 8 plots the hazard rate versus age in 3 year bands of pole mounted transformers and ground mounted transformers for 1985 -1986.

Figure 9 plots % of equipment within age range versus age in three-year bands for 11kV switchgear. Separate curves are provided for circuit breakers, circuit breakers excluding cable boxes and busbar joints, switchgear, switchgear excluding cable boxes and busbar joints.

For low voltage systems, there was a three-fold increase in aging failures between 1970 and 1985, and 25% of failures were due to aging. There was a 75% increase in aging failures for high voltage systems (and systems between 33kV and 66kV), with 18% of total due to aging. In general, 40 years is considered a reasonable lifetime for equipment.

Discussion in the paper suggests that age data is not included in the National Fault Investigation Reporting System (NAFIRS) in the United Kingdom"

Search terms and ID: Multiple, Data, Proceedings, 20

Stewart, 1998

Stewart, A. H.

"Enhanced management programs for overhead lines," Colloquium on Distribution overhead lines - economics, practice, and technology of reliability assessment, 1998, 289, 6/1 - 6/19, IEE, London, UK

An overview of activities involved in developing a cost-effective line management program, improving maintenance forecasting, and opportunities for further advancing the state-of-the-art of management programs are presented herein. The paper presents information that is general in nature as well as more specific information regarding one leading U.S. utility's experience in developing and refining its management program for overhead transmission lines. The unnamed U.S. utility uses a tool designated TL-MAP (Transmission Line-Maintenance Analysis Program) to enable analysis of the net present worth of various scenarios for performing transmission line maintenance. The tool makes use of a Markov model of changes in pole conditions. This is implemented via a decision tree structure. The use and capabilities of the tool are described in some detail.

Search terms and ID: Poles, Monitoring, Proceedings, 245

Stillman, 2000

Stillman, R. H.

"Modeling Failure Data of Overhead Distribution Systems," IEEE Transactions on Power Delivery, 2000, October, 15, 4, 1238-1242, IEEE

Case studies of widespread rural and large urban overhead distribution systems are modeled as repairable systems. Homogeneous Poisson process (HPP) is used to describe exponentially distributed random variables, while nonhomogeneous Poisson process (NHPP) is used for randomly failure events that are neither independently nor identically distributed. In this study, the measure of the failure event is expressed in terms of rate of failure per 100 km days of line exposure, or ROCOF. The article demonstrates that a Laplace test statistic can determine how satisfactory that performance is in respect of a system of distribution lines. For systems subject to preventative maintenance, previous repairs and replacement randomize the time between failures, and thus ROCOF cannot be constant. It is shown through case studies not to be the case that for lines subject to preventative maintenance, reliability is maximized and cost is minimized and ROCOF remains constant.

Data are presented from two case studies (an urban overhead distribution system and a rural overhead distribution system). Figure 1 displays a qualitative histogram of contribution of components to overhead line failures. It shows that poles, crossarms and insulators contribute to overhead failures at the earliest time interval, while conductor failures affect the system at later intervals. Figure 2 displays the cumulative failures of mercury lamps over cumulative operating time for linear (Group A) and non-linear (Group B) data. Table 1 displays the Laplace data for Group A and B in Figure 2. Figure 3 displays a trend chart of cumulative ROCOF per 100 km days versus cumulative operating time for a large urban system. The data is broken down in terms of pole failures, conductor failures, and total failures. Figure 4 displays a trend chart for sparse rural data, plotting cumulative ROCOF per 100 km days versus cumulative operating time. Figures 5 and 6 display pooled ROCOF data (and 90% confidence levels) for a large urban system and rural system, respectfully. ROCOF per 100 km of line is plotted against exposed line, in km.

Search terms and ID: Other, Technical, Journal Article, 91

Stillman, 1995

Stillman, R.H.; Mackisack, M.S.; Sharp, B. ; Lee, C.

"Case Studies in Survival Analysis of Overhead Line Components," The Second International Conference on the Reliability of Transmission and Distribution Equipment, 1995, March 29, 406, 210-214, IEE, Norwich, UK

Paper presents the hypothesis that the factor of greatest influence in the degradation of a component is aging. A three-parameter Weibull distribution is best distribution for the provided data. Three case studies of survival analysis are presented.

"Table 1 provides mortality data as a function of age, poles remaining, poles condemned, cumulative total, and characteristic population. Initial pole installation in 1964. For the Weibull model of failure, Table II presents the cumulative distribution, the probability density function, survival distribution, and the hazard rate. Figure 3 presents observed data and model-generated data of time-to-failure versus probability of failure. Figure 4 presents a model-generated sensitivity analysis of mean cost versus age to failure.

The data is probably from the Electricity Commission of Queensland, Australia."

Search terms and ID: Multiple, Technical, Data, Proceedings, 79

Stillman, 1994

Stillman, R. H.

"Probabilistic Derivation of Overstress for Overhead Distribution In-Line Structures," IEEE Transactions on Reliability, 1994, September, 43, 3, 366-374, IEEE

This paper shows how probability techniques can be applied to low and medium voltage distribution and high voltage sub-transmission lines, which use self-supporting single-pole structures. The probabilistic concept uses overlapping distributions in which the randomized stress induced by wind pressure is matched to the resisting strength of a pole structure. In this way a risk load is evaluated which optimizes structural strength and enhances the economic utility of the asset. Specific to the work is the inclusion of the degeneration of pole strength with age. This is important in distribution systems where wood is the most common construction material. The modeling uses Monte Carlo simulation to establish a failure risk of a line structure within a design return period and a life. Input to the model involves the static load imposed by line conductors and their ancillaries, random gust wind pressures (modeled by a Gumbel distribution), and a 3-parameter Weibull distribution to describe the dispersion of strength and degradation of the material. The pole overturning (wind) moment is compared to the degrading resisting (strength) bending-moment over daily or monthly intervals related to a designated lifetime. The work, for a large electric utility, analyzes treated hardwood and steel-reinforced concrete poles for new works, with emphasis on urban and semi-urban area construction. In the context of an urban and semi-rural environment, cost reductions in the order of 10% to 15% can be achieved.

Many of the figures are difficult to read due to poor copy quality. Figure 3 displays time-to-failure distributions (probability of failure versus years to failure) for differing pole types in various regions of Australia. Table 3 displays survival characteristics of SEQEB CCA poles. Data include pole age, years after installation, poles that failed/remained, number of poles at risk, and prediction, failure and reliability probabilities. Table 4 provides estimated Weibull parameters for Tasmainian CCA wood poles, S.E. Queensland CCA wood poles and S.E. Queensland concrete poles. Table 5 displays height factors in open country for the pole lengths in Table 1. These data include length, planting in ground, height above ground, maximum condition height, and GH(?), all in meters. Figure 4 is a histogram of monthly peak wind velocity for S.E. Queensland and Northern New South Wales, 1951-1991. Figure 5 displays a maximum monthly wind velocity analysis (Gumbel diagram) for S.E. Queensland and Northern New South Wales, 1951-1991. Table 7 displays an example of simulation output for the structure analyzed in Table 2. Figures 7a, 7b, and 7c display probability diagrams for CCA wood poles with applied wind moment versus resisting moment for years 1, 40 and 52, respectfully.

Search terms and ID: Poles, Data, Design, Journal Article, 99

Stoll, 1989

Stoll, Harry G.

"Least-Cost Electric Utility Planning," 1989, John Wiley & Sons, Inc., New York, New York

A handbook of electric utility planning. Focuses on the generation and transmission system, but has a good review of basic reliability approaches and models.

Search terms and ID: Non-specific, Financial, Technical, Book, 61

Tabors, 1993

Tabors, Richard

"Transmission System Management and Pricing: New Paradigms and International Comparisons," IEEE Transactions on Power Systems, 0885-8950, 1993, February, 9, 1, 206-213, IEEE

Paper discusses, in qualitative terms, three new paradigms. First, due to the economics of power generation and distribution, transmission, as opposed to generation, should be viewed as the market niche in the future. Second, the paper reviews transmission-pricing options, paying particular attention to short run marginal costing (SRMC) and long run marginal costing (LRMC). Third, the paper discusses international experiences in innovation in transmission system management and pricing.

Paper is grounded in policy discussions. The primary conclusions of the paper are 1) "While the new paradigm of a network utility is the likely outcome for U.S. and elsewhere, institutional constraints will make its accomplishment in the U.S. problematic and spotty," and 2) "Within the U.S., the transmission economics and pricing problem has been defined as one of 'open access,' and of Wheeling." The only data presented is the demand and generation, in megawatts, of electricity in various districts in the U.K.

Search terms and ID: System, Other, Journal Article, 89

Theil, 1987

Theil, G.

"Estimation of Reliability Indices for the Austrian High Voltage Network," Proceedings of the Ninth Power Systems Computation Conference, 1987, August 30, Butterworths

The paper presents a method for evaluating reliability indices of transmission networks. Many failures in electrical power distribution networks are dependent. Therefore, the reliability must be estimated for both the components and the system as a whole. The approach is based on a Bayesian procedure where the posterior distributions of expected outage duration and expected cycle time are calculated using (supposedly) known priors and data that are empirical averages of outage duration and cycle time. Assuming uniform priors and Gamma conditional distributions (distribution of empirically calculated averages for outage duration and cycle time given their expected values), the paper derives the posterior distribution of duration and cycle time and gives formulas for calculating different moments of these distrihutions. The approach is applied to reliability analysis of single lines, double circuit lines, transformers and for several types of failures such as independent outages, simultaneous outages due to short circuit or earth failures and missing operation of the protection system. These categories are identified as independent groups of failure events, which significantly contribute to the system unavailability.

Data from case studies are presented that found that dependent failures cannot be neglected because of unavailability of some categories containing dependent failure events have the same order of magnitude as the unavailability as the unavailability of independent single lines."

Data for single lines; double lines, parallel lines, transformers and busbars are presented. Single lines have the highest outage probabilities. Transformers have low outage probabilities but have longer outage durations. There are a high number of false breaker operations due to human error. Data is from the Austrian 110 kV and 220 kV network for the years from 1965 to 1984. The number of components in this system is not provided. Table 1 provides reliability indices for a number of components and component groups. The component and component groups (table rows) are: single line, double circuit line, parallel line, transformers 220/110 kV, simultaneous outage due to short circuit or earth failures, double outages, triple outages, false breaker operation, missing operation of the protection system (SVERS), busbar outages (SAFEL), busbar outages caused by human errors (SAFSA), outages of the type SVERS, SAFEL, SAFSA. The reliability indices (columns of the table) are: number of failure events, expectation of the outage duration, expectation of the cycle time, expectation of the outage frequency, expectation of the outage probability.

Search terms and ID: Multiple, Data, Equations, Proceedings, 26

Tolbert, 1995

Tolbert, L.M.; Cleveland, J.T.; Degenhardt, L.J.

"Reliability of lightning resistant overhead power distribution lines," 1995 IEEE Industrial and commercial power systems technical conference, 1995, 147 - 152, IEEE

An assessment of the 32 year historical reliability of the 13.8 kV electrical distribution system at the Oak Ridge National Laboratory (ORNL) in Tennessee, USA, has yielded several conclusions useful in the planning of industrial power systems. The system configuration at ORNL has essentially remained unchanged in the last 32 years which allows a meaningful comparison of reliability trends for the plant's eight overhead distribution lines, two of which were built in the 1960s with lightning resistant construction techniques. Meticulous records indicating the cause, duration, and location of 135 electric outages in the plant's distribution system have allowed a reliability assessment to be performed. The assessment clearly shows how differences in voltage construction class, length, age, and maximum elevation above a reference elevation influence the reliability of overhead power distribution lines. Comparisons are also made between the ORNL historical data and predicted failure rates from ANSI and IEEE industry surveys.

The data is specific to a small sample of lines at Oak Ridge National Laboratory (ORNL), but interesting none the less. The report also provides a good bit of background on approaches to reducing lightning caused outages. A single 161 kV to 13.8kV primary substation supplies electrical power at ORNL in Tennessee. Eight radial 13.8kV overhead lines originate from the substation. The lines are 0.3 to 6.3 miles long and 23 to 42 years old. These lines are the subjects of the study. The text provides a fairly detailed description of the construction of the lines especially with respect to insulation and other types of lightning protection.

Table I provides the basic failure data. For each feeder the following is presented: construction voltage, elevation, length, age, frequency of outages, and cause. Causes are categorized as weather, animal, equipment, human error, or unknown.

Table II reclassifies the outages according to ANSI/IEEE Standard 493-1990 and compares ORNL experience to industry experience as reported in IEEE Standard 493-1990, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems, 1990, pages 54, 75, 204. This table indicates the % of outages caused by different factors at ORNL and the industry average. The causes are "

Search terms and ID: Cables, Data, Causes, Proceedings, 235

Tortello, 1998

Tortello, Enzo; Bleakley, Graham

"Moving from planned to predictive maintenance," Modern power systems, 1998, August, 18, 8, 55

Discusses the installation of advanced monitoring systems at power plants and a related switch from planned to predictive maintenance.

Search terms and ID: Generators, Monitoring, Maintenance, Journal Article, 211

Transmission & Distribution, 2000(1)

Transmission & Distribution

"Crises in the making, A," Transmission & distribution world, 2000, May, NA

Provides numerous comments concerning declining maintenance of the transmission and distribution system and potential problems caused by this trend.

Search terms and ID: System, Causes, Maintenance, Journal Article, 215

Transmission & Distribution, 2000(2)

Transmission & Distribution

"America's aging transmission system," Transmission & distribution world, 2000, May, NA

Presents the opinion that deregulation will lead to the deterioration of the U.S. electric power system.

Search terms and ID: Non-specific, Causes, Journal Article, 216

Verheiden, 1976

Verheiden, E. P.

"Northwest utilities report URD product reliability, 8th Annual, NELPA," Transmission and Distribution, 1976, June, 18-23

Year-end report of underground distribution equipment failures for utilities located in the Pacific Northwest. Author states that the eight culminating years of data can be used to identify time-proven equipment.

Data tables are divided by equipment type. Finish type, total number installed, total and cumulative failures (corrosion, leak and internal) are presented for submersible transformers. Insulation type, miles installed, failures (in 1974) and cumulative failure to date data are presented for primary and low voltage cables. Type, total number, failures (in 1974) and cumulative failure data are also presented for plug-in primary and pole-top terminators and miscellaneous items. The following lists the items for which information is provided. Submersible transformer finishes: Coal Tar, Epoxy, Vinyl, Stainless, Homemade, Direct Buried, Polyester, and Fiberglass. Primary Cable types: HMW PE 175 mil, HMW PE 220 mil, XLPE 175 mil, XLPE 220 mil, XLPE 260 mil, XLPE 295 mil, Butyl-Neoprene, EPR 175 mil, EPR 220 mil, HMWP 260 mil, HMWP 280 mil, HMWP 295 mil, HMWP 345 mil. Low Voltage Cable, Type Insulation: Poly (Sodium), XLP, PVC, and Rubber Neoprene. Plug-in Primary Terminators Types: Non-LB. Rubber, Non L.B.Metal, L.B. Rubber, L.B. Metal. Pole-Top Terminators types: Porcelain Compound, Porcelain Epoxy, Porcelain Elastomer, Molded Rubber, Taped, Scotch 83A3, Porcelain Elastomeric Compound. Miscellaneous Items: Single-Phase Pad Mount Transformers, Three-phase Pad Mount Transformers, UG Street Light Cable, Secondary Connectors, No. 6 Al Duplex Street Light XLPE, Heat Shrink Covers, Insulated Secondary Bus Connectors, Primary Loadbreak Junction Bus, 15-kV 175 mil URD Cable, 600-v URD Triplex, 25-kV Loadbreak Elbows, 25-kv Porcelain Terminator With Elastomer Filler, 15-kv Porcelain Terminator With Elastomer Filler, Loadbreak (2-4 way) Junctions, 15-kV Primary Splices, 15-kV Deadend Cap, Secondary Connections, No. 2 Al Triplex XLPE.

Search terms and ID: System, Data, Report, 108

Verheiden, 1975

Verheiden, Eric P.

"URD Equipment Reliability-NELPA 7th Annual Report," Undergrounding, 1975, January/February, 12-19,44

Annual report presents reliability data for underground distribution equipment in the Pacific Northwest. Only natural failures are included in the report.

Data from the report is split into six groups: submersible transformers, primary cable, low voltage cable, plug in primary terminators, pole top terminators and miscellaneous items. For submersible transformers, data for corrosion and internal failures and average life before failure is presented. Primary cable data include miles installed, failures during the past year, failures to date and average life before failure. Low voltage cable data include thickness, miles installed, failures during the past year, failures to date and average life before failure. Plug in primary terminator; pole top terminator and miscellaneous item data include total number on system, failures during the past year, failures to date and average life before failure. This report also includes Table 7, which presents a summary of reported underground equipment failures on the Montana Power Company system during 1974. Data regarding equipment type, age and cause of failure are presented.

Search terms and ID: System, Data, Causes, Report, 123

Verheiden, 1974

Verheiden, Eric P.

"NELPA 6th Annual Report," Undergrounding, 1974, March/April, 3, 2, 62-67

Annual report presents reliability data for underground distribution equipment in the Pacific Northwest. Only natural failures are included in the report. Report copy is of poor quality.

Data from the report is split into six groups: submersible transformers, primary cable, low voltage cable, plug in primary terminators, pole top terminators and miscellaneous items. For submersible transformers, data for corrosion and internal failures and average life before failure is presented. Primary cable data include miles installed, failures during the past year, failures to date and average life before failure. Low voltage cable data include thickness, miles installed, failures during the past year, failures to date and average life before failure. Plug in primary terminator; pole top terminator and miscellaneous item data include total number on system, failures during the past year, failures to date and average life before failure.

Search terms and ID: System, Data, Causes, Report, 122

Verheiden, 1973

Verheiden, Eric P.

"5th Annual Report: U.R.D. Equipment & Materials Reliability in the Northwest, NELPA," Undergrounding, 1973, January/February, 2, 1, 12-17,30

Annual report presents reliability data for underground distribution equipment in the Pacific Northwest. Only natural failures are included in the report.

Data from the report is split into six groups: submersible transformers, primary cable, low voltage cable, plug in primary terminators, pole top terminators and miscellaneous items. For submersible transformers, data for corrosion and internal failures and average life before failure is presented. Primary cable data include miles installed, failures during the past year, failures to date and average life before failure. Low voltage cable data include thickness, miles installed, failures during the past year, failures to date and average life before failure. Plug in primary terminator; pole top terminator and miscellaneous item data include total number on system, failures during the past year, failures to date and average life before failure.

Search terms and ID: System, Data, Causes, Report, 121

Verheiden, 1972

Verheiden, Eric P.

"U.R.D. Equipment & Materials Reliability in the Northwest, Fourth Annual Report NELPA," Undergrounding, 1972, March/April, 16-23

Annual report presents reliability data for underground distribution equipment in the Pacific Northwest. Only natural failures are included in the report.

Data from the report is split into six groups: submersible transformers, primary cable, low voltage cable, plug in primary terminators, pole top terminators and miscellaneous items. For submersible transformers, data for corrosion and internal failures and average life before failure is presented. Primary cable data include miles installed, failures during the past year, failures to date and average life before failure. Low voltage cable data include thickness, miles installed, failures during the past year, failures to date and average life before failure. Plug in primary terminator; pole top terminator and miscellaneous item data include total number on system, failures during the past year, failures to date and average life before failure.

Search terms and ID: System, Data, Causes, Report, 120

Vermeulen, 1997

Vermeulen, S.T.J.A.; Rijanto, H. ; van der Duyn Schouten, F.A.

"Influence of Preventative Maintenance on the Reliability Performance of Simple Radial Distribution System Parts, The," UPEC 1997, 1997, 1077-1079

Protective system reliability is important in minimizing outages and protecting distribution equipment. A model is presented that purports to evaluate the reliability performance of power systems with multiple components and their protection systems. Because modeling a power system within a single Markov model lends to dealing with a large state space, a method is advocated that combines the results of different Markov models that describe different parts of the system.

Search terms and ID: System, Financial, Technical, Journal Article, 31

Volkmann, 1991

Volkmann, C.A.; Goldberg, S.; Horton, W.F.

"Probabilistic approach to distribution system reliability assessment, A," Third International Conference on Probabilistic Methods Applied to Electric Power Systems, 1991, 169-173, IEE, London, UK

The Pacific Gas and Electric Company (PGE), together with California Polytechnic State University in San Luis Obispo, has developed a personal computer program for evaluating the reliability levels of their electric distribution circuits. The program, called the Distribution Reliability Assessment Model (DREAM), incorporates historical outage information with circuit component failure rates and estimates of fault response and component repair times to compute expected levels of customer outage frequency and duration. The authors highlight recent enhancements to DREAM, which allow for the evaluation of both overhead and underground circuits. The authors also describe their efforts to measure the accuracy of the DREAM calculations and the application of the program in predicting the reliabilities of 180 feeders.

The paper supplies a significant amount of data used by the Dream system on failure rates. The data for underground feeders is not referenced. A table on page 169 supplies failure rates in failures per year (failures/ meter-year for cable) for non-load break elbow, molded splice, transformer, switch, HMWPE cable, XLPE cable, and fuse. A table on 170 provides data for overhead components. This data is based on 85 rural and 95 urban feeders over a period of approximately 5 years. Rural and urban failure rates in failures per year (failures/ meter-year for cable) are provided for conductor, transformer, switch, fuse, capacitor, recloser, and voltage regulator.

The conductor failure rates are for component failures not for failures due to external causes. Adjusted failure rates that include external causes are also provided for conductors, page 170.

On page 171 response or repair times are provided for both rural and urban failures. Data are provided for cable, OH Conductor, molded splice, elbow, capacitor, regulator, OH transformer, UG transformer, OH switch, UG switch, recloser, OH fuse, UG fuse, and external electrical."

Search terms and ID: Multiple, Financial, Data, Proceedings, 240

Walker, 1983

Walker, A.J.

"Degradation of the Reliability of Transmission and Distribution Systems During Construction Outages," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 112-118, IEE, London, United Kingdom

This paper discusses standards regarding thermal capabilities not being exceeded during single or double circuit outages during construction projects. The standards are expressed in terms of the design of the system rather than the risk of loss or the availability of supply to consumers. Furthermore, discusses how reliability data can be used in cost/benefit analyses regarding the degradation of reliability during construction outages.

This article provides fault statistics for active failure rates of switchgear and overhead line faults and provides reliability data for 275kV systems. Active failure rate of 275 kV switchgear is about 0.01 faults per year. 1.5% of all active supergrid overhead line faults - reported over a five-year period- caused simultaneous tripping on double circuit lines. Some comments on overhead line fault data are illegible in our copy.

Search terms and ID: System, Technical, Data, Proceedings, 6

Ward, 2001

Ward, B.; Traub, T.; Alfieri, M.; Bolton, S.; Chu, D.; Hammers, J.

"Integrated Monitoring and Diagnostics: Maintenance Ranking and Diagnostics Algorithms for Transformers," 1001951, 2001, October, EPRI, Palo Alto, California

This report describes algorithms to monitor problems that could potentially develop within power transformers and associated load tap changing and auxiliary equipment. Used in

conjunction with EPRI's Maintenance Management Workstation (MMW) or other suitable software, the algorithms can provide prioritized indication and alerts to focus attention on transformer problems before they lead to more extensive damage. The report also provides a concise table that links each parameter that can be measured or monitored to the problem categories and examples. This information can be used by less experienced personnel to understand and respond to off normal conditions of power transformers.

Provides an extensive list of tests and a guide to their purpose, interpretation, and appropriate response. Does not link test results to the probability of failure except in a qualitative manner.

Search terms and ID: Transformers, Monitoring, Report, 267

Wareing, 1998

Wareing, J.B.

"Failure modes in overhead lines," Colloquium on Distribution overhead lines - economics, practice, and technology of reliability assessment, 1998, 289, 2/1 - 2/10, IEE, London, UK

This report covers failure modes in overhead lines and looks at modes of failure of overhead line conductors, joints and terminations, insulators, pole mounted equipment and support structures under normal 'wear and tear', overloading and adverse weather conditions.

The only data provided are expected lifetimes of several components.

Search terms and ID: Multiple, Causes, Proceedings, 241

Watson, 1981

Watson, W.G.; Walker, A.J.; Fisher, A.G.

"Evaluation of the cost and reliability implications of alternative engineering investment policies for replacement of plant on ageing distribution systems," International Conference on Electricity Distribution, 1981, 326-30, IEE, London, UK

As a result of the changes in load growth rate in recent years the average age of many distribution systems has been increasing, leading to a growing need for replacement of old distribution plant. The paper describes the development of workload forecasts for the replacement of plant in one Area Board over the next thirty years, and contains examples showing consequences, for performance and cost, of alternative replacement strategies for switchgear in 11 kV urban networks. The performances of these networks are evaluated using a computer program that calculates the principal reliability of supply indices. Cost-benefit assessments are made of the alternative replacement strategies considered.

This report presents interesting data related to aging components. Table 1 presents the expected lives of various distribution components. Max, Min, and Median expected lives in years are presented for 132kV and 33kV underground cables, 11kV paper underground cables, LV lead sheath underground cables, LV aluminum sheath underground cables, overhead copper conductors, overhead aluminum conductors, wood poles, steel towers, 132/33kV and 33/11kV transformers, 11kV/LV ground mounted transformers, 11kV/LV pole mounted transformers, circuit breakers, and oil switches and fuses. Figure 3 plots switchgear age groups against % of equipment experiencing failures and defects. Included are switch fuses defects, circuit breaker failures, mechanisms, and insulation. In addition fault rates per 100km-year and per 100 unit-year for cable, transformer, automatic switch fuse, and feeder sectioning unit. Event durations are for switching operations, travel between substations, operation of oil switch, operation of source circuit breaker, backfeed via LV system, inspection of earth fault indicator, transfer transformer tail at FSU, repair cable, replace transformer, replace switchgear, maintain one substation, maintain two substations, and maintain three substations. Data is drawn from the experience of the Eastern Electricity Board in the UK. In 1980 they had a load of just over 5,000 MW and approximately 50,000 substations.

Search terms and ID: Multiple, Data, Financial, Proceedings, 229

Welch, 2001

Welch, Greg; Willis, H. Lee; Lux, A.

"Prioritizing Operations and maintenance for aging T&D systems workshop," 2001, February 20, EUCI

Reliability centered maintenance is discussed in some detail. It begins by discussing why utilities are under pressure to provide higher reliability at lower cost. It moves on to discuss benefit cost ratios and an RCM based ranking scheme for reliability improvement projects. It provides a simplified example. It ends with recommendations on establishing an RCM based prioritization system.

This presentation has very little data. There is a table for Power Transformers with a note, "Developed for illustrative purposes only. Do not apply to specific maintenance decisions. It lists for various transformer equivalent ages the impact of variance maintenance or refurbishment actions.

Search terms and ID: System, Maintenance, Financial, Proceedings, 223

West, 1997

West, J. Doug

"Approach To Minimize the Maintenance Cost For An Aircraft Electrical Power Generator, An," Unknown, 1997

The paper describes a Type II maintenance policy that uses the non-homogeneous Poisson process (NHPP) with a power law intensity function to describe the failure data and the forward recurrence time. The Type II policy requires that the system be overhauled at the first failure past a pre-specified overhaul interval, and that only minimal repairs are accomplished until this interval is reached.

The contribution of the paper may be summarized as developing the Type II policy for the NHPP process by modifying the existing theory to use the concepts of repairable systems rather than non-repairable ones. The paper derives a cost function, which depends upon the replacement interval T and calculates a replacement time so as to minimize the cost function.

The author first presents a summary of failure models and non-homogeneous Poisson process and continues with the approach of Muth (An Optimal Decision Rule for Repairs vs Replacement, vol. R-26, no. 3, pp. 179-181. August 1977) to derive a cost as a function of overhaul interval. Arguing that Muth's concept of mean residual life time (MRLT) is not defined for repairable systems, the author replaces MRLT with forward recurrence time and calculates this quantity on the basis of the distribution for a specific form of NHPP called power-law process. The same distribution is used to calculate the expected number of failures within the interval of interest. Finally, the author applies the method to minimizing the replacement cost for an aircraft integrated drive generator. Based on this analysis and using two sets of parameter values for the power law process, the paper arrives at overhaul intervals of between 3360 and 7270 flight hours.

Under a Type II maintenance policy, replacement resets age of the system back to 0. Repairs do not change the age of the system. Comparing cost versus overhaul interval is a function of operation time.

Search terms and ID: Other, Technical, Maintenance, Proceedings, 24

Williams, 1983

Williams, W.P.; Mudge, S.G.

"Reliability Assessment of Industrial Power Networks," Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 107-111, IEE, London, United Kingdom

In industrial networks, it is common for designers to perform multiple studies regarding load flow, stability, etc., but reliability assessments are based largely on experience, which leads to over design. This article discusses expressing reliability in terms of degree of probability. The article contends that a probabilistic approach allows for economic comparisons between alternating networks and differing maintenance and operating practices.

The article includes input data for the probabilistic model that includes reliability indices for circuit breakers, transformers, busbars, and feeder cables for differing network configurations. The article does not site the source of the data. The data is found in Table I components covered include: 33 kV circuit breaker, 33/11 KV transformer, 11 kV circuit-breaker, 11kV busbar, 11 kV incoming cable, 11kV feeder cable (rows). Data provided on each component includes failures per year and repair time in hours (columns). Maintenance data is provided in the same table for 33/11 kV interconnector, 11kV bus-section, 11 kV busbar, 11 kV feeder (rows). The data provided are outages per year and outage time in hours (columns)

Search terms and ID: Multiple, Technical, Data, Journal Article, 5

Willis, 2001(1)

Willis, H. Lee; Welch, Gregory V.; Schrieber, R.R.

"Aging Power Delivery Infrastructures," 2001, Marcel Dekkar, Inc., New York, NY

This book provided mostly qualitative reference and tutorial guide on aging power delivery systems. The book covers planning, engineering, operations and maintenance, and management of aging power systems. The 16 chapters are: 1) Aging Power Delivery Infrastructures; 2) Power Delivery Systems; 3) Customer Demand for Power and Reliability of Service; 4) Power System Reliability and Reliability of Service; 5) Cost and Economic Evaluation; 6) Equipment Inspections, Testing, and Diagnostics; 7) Aging Equipment and Its Impacts; 8) Obsolete System Structures; 9) Traditional Reliability Engineering Tools and Their Limitations; 10) Primary Distribution Planning and Engineering Interactions; 11) Equipment Condition Assessment; 12) Prioritization Methods for O&M; 13) Planning Methods for Aging T&D Infrastructures; 14) Reliability Can Be Planned and Engineered; 15) Strategy, Management and Decision-Making; and 16) Guidelines and Recommendations.

Book is primarily qualitative. Some data is presented, but its background is not clearly stated. Of particular interest is Table 1.3, which presents the percentage breakdown of contributing factors to aging infrastructure problems and Figure 7.5, which displays failure rates of underground cables as a function of age. Section at the end of each chapter may contain several references worth investigating.

Search terms and ID: System, General, Data, Book, 80

Willis, 2001(2)

Willis, H.L.; Brown, R.

"Reliability engineering and differentiated reliability service," 2001, September 11-13, ABB

The document is comprised of the overheads from a three-day course. The topics covered were: overview of reliability engineering, overview of distribution systems, reliability indices, outage data and benchmarking, customer cost of reliability, performance based rates, causes of poor reliability, storms and major events, reliability and the power industry, two Q planning, systems approach, aging infrastructures, aging and its effect on systems, differentiated reliability, reliability modeling, risk analysis, marginal cost/benefit analysis, improving reliability, optimizing reliability, and differentiating reliability. Obviously the course emphasizes breadth over depth on any one subject. In each area, generally typical practices or approaches are contrasted with more modern and recommended approaches.

Limited data is provided. Reliability Modeling, page 21 provides a table of failure rate and mean time to repair for substation equipment including power transformers, circuit breakers, disconnect switches, and air insulated buswork; overhead equipment including transmission lines, distribution lines, switches/fused cutouts, and pole mounted transformers; and underground equipment including cable, pad-mount switches, pad-mount transformers, and cable terminations/joints. Reliability Modeling, page 22 provides three graphs also found in other ABB publications. These are failure rate versus equipment age graphs for 25-kV solid cable, 25-kV paper cable, 15-kV solid cable, 15-kV paper cable, 25-kV solid cable joints, 25-kV paper cable joints, 15-kV solid cable joints, 15-kV paper cable joints, 25-kV paper-solid cable joints, 15-kV paper-solid cable joints, 25-kV pad-mounted transformers, and 15-kV pad-mounted transformers.

Search terms and ID: System, Financial, Data, Presentation, 251

Willis, 1997

Willis, H. L.

"Power distribution planning reference book," 1997, Marcel Dekker, New York, New York

Provides a modern source of information for distribution planners and engineers who must meet demands for ever-greater performance while working in an environment of intense cost containment and regulatory review. Addresses the layout and design of power distribution systems in a comprehensive manner, from subtransmission through the service level. The book emphasizes economy as the primary goal of distribution design, and examines in great detail how distribution systems can be designed to achieve adequate performance and reliability at the lowest possible cost, and how cost interacts with electrical performance, reliability and customer service quality. It reviews traditional approaches to designing each component of the subtransmission and distribution system. It also considers new computerized analysis and optimization methods and current concepts including value-based planning, budget-constrained planning, partial T&D forecasting, multiscenario planning, and deregulated utility planning.

Search terms and ID: System, Financial, Technical, Book, 252

Witt, 1996

Witt, James H.; Galdry, Thomas H.

"Improving Overhaul/Replacement Decisions," PWR 1996 Joint Power Generation Conference, ASME 1996, 1996, 30, 265-275, ASME

A large percentage of generation equipment exhibits reduced reliability characteristics with subsequent overhauls. Using data from boiler recirculation pumps, this article suggests implementing software that analyzes reliability trends to determine the effects of overhauls, replacements or doing nothing on equipment. Overhauls were found to be inducing failure events that had to be absorbed before the benefits of the overhaul could be realized. The effects of overhauls were not consistent and overhauls appeared to be performed too frequently. The article presents the OVERT program, which describes equipment's reliability using Weibull distribution based on failure histories.

Linear regression curves and reverse attribution tests (RAT) and Mann-Whitney tests were performed. Data creates a bathtub curve.

Search terms and ID: Generators, Technical, Data, Journal Article, 28

Xourafas, 1987

Xourafas, C.B; Krishnasamy, S.G.

"Prediction of distribution line service reliability by probability methods," Prohabilistic Methods Applied to Electric Power Systems Proceedings of the First International Symposium, 1987, 195-202, Pergamon, Oxford, UK

A computer program based on prohabilistic methods of analysis/design has been developed for predicting the mode and probability of failure of tangent pole framings. The results from this program are used to perform failure-mode-effect and criticality analysis (FMECA) at the structural component level, and to predict the customer service reliability.

Table 1.0 presents failure rates for two designs the calculations are site specific and there are no details of the data sources.

Search terms and ID: Poles, Technical, Data, Proceedings, 227

B
EQUIPMENT FAILURE RATE DATABASE

Table B-1
Simple Failure Rates

Equipment Database		Failure rates								
Buswork										
	Ref	Mok, 1996								
Busbar	/yr	1.50E-03								
	Ref	Dalabeih, 1995								
132 kV busbars	/yr	1.10E-02								
	Ref	Hale, 2000	Willis, 2001(2) low	Willis, 2001(2)hi gh	Heising, 1974	IEEE, 1974(5)				
Switchgear, bare bus	/yr	1.02E-02	2.00E-03	4.00E-02	6.30E-04	4.40E-04				
	Ref	Hale, 2000	Heising, 1974	IEEE, 1974(5)						
Switchgear, insulated bus	/yr	3.90E-04	1.70E-03	1.27E-03						
	Ref	Hale, 2000								
Bus duct, all types	/yr	3.00E-04								
Cable/conductor										
	Ref	Willis, 2001(2)low	Willis, 2001(2) high	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Volkmann, 1991urb	Chen, 1995		

Overhead conductor	/yr	3.00E-01	1.80E+00	8.05E-02	8.05E-02	1.22E-02	1.93E-02	9.66E-02		
	Ref	Hale, 2000								
>15kV	/yr	2.17E-02								
	Ref	Hale, 2000	Heising, 1974	Horton, 1991 rural	Horton, 1991 urban	Arceri, 1976				
<15kV	/yr	2.49E-01	7.59E-02	1.22E-02	1.98E-02	2.00E-01				
	Ref	Hale, 2000	Willis, 2001(2) low	Willis, 2001(2) high	Verheiden 1976	Heising, 1974	Arceri, 1976	IEEE, 1974(5)	Chen, 1995	
Underground cable	/yr	3.06E-02	5.00E-02	4.00E-01	8.12E-03	1.17E-03	2.00E-01	3.99E-02	4.83E-02	
	Ref	Verheiden, 1976	Heising, 1974							
Approx 600v solid	/yr	2.19E-03	7.35E-04							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
15kV solid	/yr	6.00E-02	8.00E-02							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25kV solid	/yr	1.20E-01	4.50E-01							
	Ref	Horton, 1979								

Direct buried Polyethylene (PE)	/yr	2.80E-02								
	Ref	Verheiden, 1976	Volkmann, 1991rural	Volkmann, 1991urb	Goldberg, 1987					
Direct buried HMWPE unjacketed	/yr	7.66E-03	3.34E-02	3.34E-02	5.00E-02					
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb	Verheiden 1976	Volkmann, 1991rural	Volkmann, 1991urb	Goldberg, 1987			
Direct buried XLPE unjacketed	/yr	3.22E-02	4.02E-02	3.80E-03	2.00E-03	2.00E-03	3.00E-03			
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb							
Direct buried TRXLPE-SF-PEEJ	/yr	2.25E-02	3.06E-02							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb							
In Duct XLPE	/yr	4.02E-02	4.02E-02							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb							
In Cov. Duct XLPE	/yr	3.70E-02	3.70E-02							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb							
In C.E. Duct XLPE	/yr	3.22E-02	3.22E-02							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb							

In C.E. Duct TRXLPE-SF-PEEJ	/yr	2.25E-02	2.25E-02							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
15kV paper	/yr	2.00E-02	6.00E-02							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25kV paper	/yr	2.00E-02	6.00E-02							
Cable/Conductor Connections										
Overhead										
	Ref	Verheiden, 1976								
Pole top terminators, molded rubber	/yr	5.73E-05								
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
Underground splices/terminations	/yr	1.00E-04	2.00E-03							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb	Verheiden 1976	Volkmann, 1991rural	Volkmann, 1991urb	Goldberg, 1987	Arceri, 1976	IEEE, 1974(5)	Chen, 1995
Splices	/yr	1.00E-03	1.00E-03	2.10E-03	1.90E-04	1.90E-04	6.00E-04	1.00E-03	9.10E-04	6.00E-04

	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
15kV Solid splice	/yr	1.80E-01	8.00E-01							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25-kV Solid splice	/yr	1.80E-01	8.80E-01							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
15kV Paper-Solid splice	/yr	8.00E-02	2.00E-01							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25kV Paper-Solid splice	/yr	1.00E-01	3.50E-01							
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25kV/15kV Paper splice	/yr	4.00E-02	1.20E-01							
	Ref	Goldberg, 1987	Chen, 1995							
Elbows	/yr	6.00E-04	6.00E-04							
	Ref	Hale, 2000	Godfrey, 1996 rural	Godfrey, 1996 urb	Verheiden 1976					
Loadbreak elbows/terminators	/yr	3.70E-04	1.50E-03	1.50E-03	2.63E-04					

	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb	Verheiden , 1976	Volkmann, 1991rural	Volkmann, 1991urb	Arceri, 1976			
Non-loadbreak elbows/terminators	/yr	1.00E-03	1.00E-03	2.83E-04	1.90E-04	1.90E-04	6.00E-04			
	Ref	Verheiden, 1976								
15-kV deadend cap	/yr	3.00E-03								
	Ref	Hale, 2000	Volkmann, 1991rural	Volkmann, 1991urba	Horton, 1991 rural	Horton, 1991 urban				
Capacitor Banks	/yr	1.74E-01	1.05E-02	8.50E-03	1.05E-02	8.50E-03				
Poles										
	Ref	Stillman, 1994								
Wooden	/yr	3.34E-05								
	Ref	Stillman, 1994								
Concrete	/yr	0.00E-00								
	Ref									
Switches/Circuit breakers/fuses	/yr									
	Ref	Chen, 1995								

Switches	/yr	4.00E-03								
	Ref	Hale, 2000	Willis, 2001(2) low	Willis, 2001(2) high	Heising, 1974	IEEE, 1974(5)				
Substation disconnect switches	/yr	1.50E-04	4.00E-03	1.60E-01	6.10E-03	5.42E-03				
0	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Volkmann, 1991urb	Horton, 1991 rural	Horton, 1991 urban	
Overhead switches	/yr	4.00E-03	1.40E-02	1.00E-03	1.00E-03	1.26E-03	7.75E-04	1.26E-03	7.75E-04	
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Volkmann, 1991rural	Volkmann, 1991urb	Goldberg, 1987				
Underground pad mount switches	/yr	1.00E-03	1.00E-02	4.00E-03	4.00E-03	4.00E-03				
	Ref	Hale, 2000								
Automatic transfer	/yr	5.12E-02								
	Ref	Hale, 2000								
Manual transfer	/yr	8.70E-04								
	Ref	Hale, 2000								
Oil filled, >5kV	/yr	1.76E-03								
	Ref	Hale, 2000								
Static	/yr	2.25E-03								

	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Mok, 1996	IEEE, 1974(5)	Degen, 1995				
Circuit breakers	/yr	3.00E-03	2.00E-02	3.00E-03	3.40E-03	6.72E-03				
	Ref	Hale, 2000								
< 600V	/yr	6.40E-04								
	Ref	Steed, 1986								
11 kV	/yr	2.00E-04								
	Ref	Fletcher, 1995								
63-100kV	/yr	2.80E-03								
	Ref	Dalabeih, 1995								
132 kV	/yr	3.60E-02								
	Ref	Hale, 2000	Heising, 1974							
Circuit breaker 3 Phase, fixed	/yr	0.00E+00	5.20E-03							
	Ref	Hale, 2000	Heising, 1974							
Circuit breaker Drawout	/yr	1.11E-03	3.00E-03							
	Ref	Hale, 2000								
Circuit breaker vacuum	/yr	2.01E-02								

	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Volkmann, 1991urb	Horton, 1991 rural	Horton, 1991 urban	Chen, 1995		
Recloser	/yr	1.50E-02	1.50E-02	1.50E-02	1.44E-02	1.50E-03	1.44E-03	5.00E-03		
	Ref	Chen, 1995								
Fuses	/yr	3.70E-03								
	Ref	Hale, 2000	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Volkmann, 1991urb	Mok, 1996	Horton, 1991 rural	Horton, 1991 urban	
Overhead	/yr	8.70E-04	3.00E-03	3.00E-03	4.50E-03	3.74E-03	2.00E-03	4.50E-03	3.74E-03	
	Ref	Hale, 2000	Volkmann, 1991rural							
Underground	/yr	8.70E-04	4.00E-03							
	Ref	Goldberg, 1987	Mok, 1996	Chen, 1995						
Transformers	/yr	2.00E-03	1.50E-02	2.00E-03						
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
Substation power transformers	/yr	1.50E-02	7.00E-02							
	Ref	Dalabeih, 1995								

132/33kV transformer	/yr	1.50E-02								
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Horton, 1991 rurel	Horton, 1991 urban	Arceri, 1976	
Overhead Pole mounted	/yr	1.00E-03	4.00E-03	3.00E-03	5.00E-03	2.71E-04	2.71E-04	6.14E-04	4.40E-03	
	Ref	Freeman, 1996								
11kV/415V pole mounted	/yr	1.60E-05								
	Ref	Hale, 2000	Willis, 2001(2) low	Willis, 2001(2) high	Godfrey, 1996 rural	Godfrey, 1996 urb	Volkmann, 1991rural	Heising, 1974	IEEE, 1974(5)	
Pad-mounted	/yr	2.89E-03	2.00E-03	3.00E-03	2.00E-03	3.00E-03	2.30E-03	4.10E-03	4.73E-03	
	Ref	Heising, 1974								
601v-15kV	/yr	3.00E-03								
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Heising, 1974						
15kV	/yr	7.00E-03	4.50E-02	1.30E-02						
	Ref	Willis, 2001(2) low	Willis, 2001(2) high							
25kV	/yr	1.20E-02	3.20E-02							

	Ref	Verheiden, 1976	Arceri, 1976							
3 phase	/yr	6.21E-03	6.20E-03							
	Ref	Verheiden, 1976	Arceri, 1976							
1 phase	/yr	3.63E-03	4.00E-03							
	Ref	Hale, 2000								
Forced air	/yr	1.08E-02								
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urb	Verheiden 1976						
Submersible	/yr	3.00E-03	3.00E-03	3.08E-03						
	Ref	Verheiden, 1976								
Vinyl	/yr	2.49E-03								
	Ref	Verheiden, 1976								
Stainless	/yr	1.38E-03								
	Ref	Arceri, 1976								
1 phase below grade	/yr	3.80E-03								
Other										
	Ref	Hale, 2000	Godfrey, 1996 rural	Godfrey, 1996 urb	Arceri, 1976					
Arrester, lightning	/yr	1.32E-03	2.00E-04	2.00E-04	2.00E-04					

	Ref	Hale, 2000								
Battery	/yr	7.02E-03								
	Ref	Hale, 2000								
Inverters, all types	/yr	4.82E-03								
	Ref	Hale, 2000								
Meter, electric	/yr	3.60E-04								
	Ref	Hale, 2000	Heising, 1974							
Rectifiers, all types	/yr	4.47E-03	2.98E-02							
	Ref	Verheiden, 1976								
Secondary connectors	/yr	7.81E-05								
	Ref	Hale, 2000								
UPS	/yr	9.20E-04								
	Ref	Hale, 2000	Volkmann, 1991rural	Volkmann, 1991urb	Horton, 1991 rural	Horton, 1991 urban				
Voltage Regulator, static;	/yr	3.63E-02	2.88E-02	2.88E-02	2.88E-02	2.88E-02				

Table B-2
Repair Times

Equipment Database		**Repair times in hours**					
Buswork	Ref	Mok, 1996					
Busbar	Hours	3.5					
	Ref	Dalabeih, 1995					
132 kV busbars	Hours	2.5					
	Ref	Hale, 2000	Heising, 1974				
Switchgear, bare bus	Hours	27.3	17.3				
	Ref	Heising, 1974.0					
Switchgear, insulated bus	Hours	261.0					

Cable/conductor							
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urban	Chen, 1995			
Overhead conductor	hours	3.0	2.5	1.5			
	Ref	Hale, 2000					
>15kV	hours	2.5					
	Ref	Hale, 2000	Heising, 1974				
<15kV	hours	1.8	31.6				
	Ref	Goldberg, 1987	Willis, 2001(2) low	Willis, 2001(2) high	Hale, 2000	Chen, 1995	Heising, 1974
Underground cable	hours	1.5	3.0	30.0	6.8	2.3	95.5
	Ref	Goldberg, 1987	Volkmann, 1991rural	Volkmann, 1991urban			
Direct buried HMWPE unjacketed	hours	1.5	6.0	4.8			

	Ref	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban		
Direct buried XLPE unjacketed	hours	6.0	4.8	10.0	9.5		
	Ref	Godfrey, 1996 urban					
Direct buried TRXLPE-SF-PEEJ	hours	9.5					
	Ref	Godfrey, 1996 urban					
In Duct XLPE	hours	7.5					
	Ref	Godfrey, 1996 urban					
In Cov. Duct XLPE	hours	7.5					
	Ref	Godfrey, 1996 urban					
In C.E. Duct XLPE	hours	5.5					

	Ref	Godfrey, 1996 urban					
In C.E. Duct TRXLPE-SF-PEEJ	hours	5.5					
Cable/Conductor Connections							
Overhead							
	Ref						
Pole top terminators, molded rubber	hours						
	Ref	Willis, 2001(2) low	Willis, 2001(2) high				
Underground splices/terminations	hours	2.0	4.0				
	Ref	Goldberg, 1987	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban	Chen, 1995
Splices	hours	1.5	6.0	4.4	5.5	5.5	3.5

	Ref	Goldberg, 1987	Chen, 1995				
Elbows	hours	3.5	1.7				
	Ref	Hale, 2000	Godfrey, 1996 rural	Godfrey, 1996 urban			
Loadbreak elbows/terminators	hours	0.8	5.5	5.5			
	Ref	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban		
Non-loadbreak elbows/terminators	hours	4.5	4.5	5.5	5.5		
	Ref	Hale, 2000	Volkmann, 1991rural	Volkmann, 1991urban			
Capacitor Banks	hours	2.3	2.3	2.4			

Switches/Circuit breakers/fuses							
	Ref	Chen, 1995					
Switches	hours	1.0					
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Heising, 1974			
Substation disconnect switches	hours	1.5	12.0	3.6			
0	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban
Overhead switches	hours	1.0	4.0	2.6	2.9	5.5	5.5
	Ref	Goldberg, 1987	Willis, 2001(2) low	Willis, 2001(2) high	Volkmann, 1991rural	Volkmann, 1991urban	
Underground pad mount switches	hours	1.5	1.0	5.0	2.3	4.8	

	Ref	Hale, 2000					
Automatic transfer	hours	4.1					
	Ref	Hale, 2000					
Static	hours	13.0					
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Mok, 1996	Godfrey, 1996 rural	Godfrey, 1996 urban	
Circuit breakers	hours	6.0	80.0	4.0	17.0	17.0	
	Ref	Hale, 2000					
< 600V	hours	1.0					
	Ref	Dalabeih, 1995					
132 kV	hours	2.0					
	Ref	Heising, 1974					
Circuit breaker 3 Phase, fixed	hours	5.8					
	Ref	Hale, 2000	Heising, 1974				
Circuit breaker Drawout	hours	3.1	129				
	Ref	Hale, 2000					
Circuit breaker vacuum	hours	10.7					
	Ref	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban	Chen, 1995	

Recloser	hours	4.3	2.2	4.0	4.0	1.5	
	Ref	Chen, 1995					
Fuses	hours	1.0					
	Ref	Mok, 1996	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban	
Overhead	hours	1.8	3.6	3.2	2.0	2.0	
	Ref	Volkmann, 1991rural	Volkmann, 1991urban				
Underground	hours	4.3	2.2				
	Ref	Goldberg, 1987	Mok, 1996	Chen, 1995			
Transformers	hours	5.5	10.0	2.5			
	Ref	Willis, 2001(2) low	Willis, 2001(2) high				
Substation power transformers	hours	15.0	480.0				
	Ref	Dalabeih, 1995					
132/33kV transformer	hours	2.0					
	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban
Overhead Pole mounted	hours	3.0	8.0	4.0	5.0	3.5	3.0

	Ref	Willis, 2001(2) low	Willis, 2001(2) high	Volkmann, 1991rural	Volkmann, 1991urban	Godfrey, 1996 rural	Godfrey, 1996 urban
Pad-mounted	hours	2.0	6.0	7.0	5.3	3.5	3.0
	Ref	Heising, 1974					
601v-15kV	hours	174					
	Ref	Hale, 2000					
Forced air	hours	132.4					
	Ref	Godfrey, 1996 rural	Godfrey, 1996 urban				
Submersible	hours	3.5	3.0				
Other							
	Ref	Hale, 2000	Godfrey, 1996 rural	Godfrey, 1996 urban			
Arrester, lightning	hours	4.0	2.0	2.0			
	Ref	Hale, 2000					
Inverters, all types	hours	26.0					
	Ref	Hale, 2000					
Meter, electric	hours	1.0					
	Ref	Hale, 2000	Heising, 1974				
Rectifiers, all types	hours	16.0	380				
	Ref	Hale, 2000	Heising, 1974				
Voltage Regulator, static;	hours	74.8	2.8	2.0			

Table B-3
Aging Data

Equipment Database		**Aging Data**			
	Source	lambda10	lambda20	lambda30	Notes
Buswork					
Cable/conductor					
Overhead conductor					
<15kV	Godfrey, 1996	8.05E-02	8.81E-02	9.30E-02	Based on Weibull distribution and 10th year and terminal year rates
<15kV	Godfrey, 1996	3.22E-02	4.16E-02	4.83E-02	Based on Weibull distribution and 10th year and terminal year rates
Underground cable	Medek, 1989	2.50E-03	3.40E-02	1.40E-01	Report stated that failures were approximated by a Iowa S3 statistical normal curve with a mean of 28 years. The best references I could find on this was that 3/4 of the assets would die within 30% of the mean. That is approximated by a normal with mean 28 and sd of 7.25.
Underground cable	Dedman, 1990	4.32E-02	6.94E-02	9.15E-02	I fitted a Weibull distribution to the failure data that they supplied by year of installation
15kV solid	Willis, 2001(2)	6.00E-02	7.00E-02	8.00E-02	Read from an ABB greph
25kV solid	Willis, 2001(2)	1.20E-01	2.80E-01	4.50E-01	Read from an ABB graph
Direct buried Polyethylene (PE)	Horton, 1979	2.80E-02	5.63E-02	8.51E-02	Calculated based on F(t) the cumulative failure function defined as (k/(n+1))*t^(n+1). Used .01 miles as the unit.

Direct buried HMWPE unjacketed	Horton, 1991(1)	1.40E-02	2.10E-02	3.10E-02	Calculated based on a failure rate of the form f(t)=Kt^n, w. K=.65 and n=0.3
Direct buried XLPE unjacketed	Horton, 1991(1)	1.30E-03	1.30E-03	1.40E-03	Calculated based on a failure rate of the form f(t)=Kt^n, w. K=.13 and n=0
Direct buried XLPE unjacketed	Horton, 1991(1)	4.70E-03	4.90E-03	5.20E-03	Calculated based on a failure rate of the form f(t)=Kt^n, w. K=.45 and n=0
Direct buried XLPE unjacketed	Godfrey, 1996	3.22E-02	6.44E-02	9.66E-02	Based on Weibull distribution and 10th year and terminal year rates
Direct buried XLPE unjacketed	Gedfrey, 1996	4.02E-02	8.05E-02	1.21E-01	Based on Weibull distribution and 10th year and terminal year rates
Direct buried XLPE unjacketed	Horton, 1979	6.00E-03	1.20E-02	1.80E-02	Calculated based on F(t) the cumulative failure function defined as (k/(n+1))*t^(n+1). Used .01 miles as the unit.
Direct buried TRXLPE-SF-PEEJ	Godfrey, 1996	2.25E-02	4.56E-02	6.88E-02	Based on Weibull distribution and 10th year and terminal year rates
Direct buried TRXLPE-SF-PEEJ	Godfrey, 1996	3.06E-02	5.63E-02	8.05E-02	Based on Weibull distribution and 10th year and terminal year rates
In Duct XLPE	Godfrey, 1996	4.02E-02	8.05E-02	1.21E-01	Based on Weibull distribution and 10th year and terminal year rates
In Cov. Duct XLPE	Godfrey, 1996	3.70E-02	7.33E-02	1.09E-01	Based on Weibull distribution and 10th year and terminal year rates
In C.E. Duct XLPE	Godfrey, 1996	3.22E-02	6.44E-02	9.66E-02	Based on Weibull distribution and 10th year and terminal year rates
In C.E. Duct TRXLPE-SF-PEEJ	Godfrey, 1996	2.25E-02	4.56E-02	6.88E-02	Based on Weibull distribution and 10th year and terminal year rates
15kV paper	Willis, 2001(2)	2.00E-02	4.00E-02	6.00E-02	Read from an ABB graph

25kV paper	Willis, 2001(2)	2.00E-02	4.00E-02	6.00E-02	Read from an ABB graph
Cable/Conductor Connections					
Overhead					
Underground splices/terminations					
Splices	Godfrey, 1996	1.00E-03	1.00E-03	1.00E-03	Based on Weibull distribution and 10th year and terminal year rates
15kV Solid splice	Willis, 2001(2)	1.80E-01	4.60E-01	8.00E-01	Read from an ABB graph
25-kV Solid splice	Willis, 2001(2)	1.80E-01	5.30E-01	8.80E-01	Read from an ABB graph
15kV Paper-Solid splice	Willis, 2001(2)	8.00E-02	1.50E-01	2.00E-01	Read from an ABB graph
25kV Paper-Solid splice	Willis, 2001(2)	1.00E-01	2.30E-01	3.50E-01	Read from an ABB graph
25kV/15kV Paper splice	Willis, 2001(2)	4.00E-02	8.00E-02	1.20E-01	Read from an ABB graph
Elbows					
Loadbreak elbows/terminators	Horton, 1991(1)	9.00E-04	1.80E-03	3.60E-03	Calculated based on a failure rate of the form f(t)=Kt^n, w. K=.00009 and n=1
Loadbreak elbows/terminators	Godfrey, 1996	1.50E-03	2.00E-03	2.37E-03	Based on Weibull distribution and 10th year and terminal year rates
Non-loadbreak elbows/terminators	Godfrey, 1996	1.00E-03	1.00E-03	1.00E-03	Based on Weibull distribution and 10th year and terminal year rates

Capacitor Banks	Faraq, 1999	2.50E-02	7.07E-02	1.30E-01	Calculated based Weibull with Alpha 25.13 and Beta 2.5
Capacitor Banks	Faraq, 1999	1.94E-01	1.91E+00	7.27E+00	Calculated based Weibull with Alpha 12.04 and Beta 4.3
Poles					
Wooden	Stillman, 1994	3.34E-05	3.01E-04	1.09E-03	Based on three parameter Weibul Alpha=96, Beta=4.17, gamma=0
Wooden	Stillman, 1994	3.11E-04	5.42E-03	2.04E-02	Based on three parameter Weibul Alpha=43, Beta=3.6, gamma=5
Concrete	Stillman, 1994	0.00E+00	0.00E+00	2.37E-05	Based on three parameter Weibul Alpha=114, Beta=4, gamma=20
Switches/Circuit breakers/fuses					
Switches	Steed, 1986	1.80E-04	3.00E-04	5.00E-04	Read from graph, this is for 11kV and includes all components such as cable boxes and busbar joints
Overhead switches	Watson, 1981	5.00E-04	2.10E-03	2.70E-03	Read from graph with extrapolation from 25 to 30 years
Overhead switches	Godfrey, 1996	1.00E-03	1.00E-03	1.00E-03	Based on Weibull distribution and 10th year and terminal year rates
Circuit breakers	Watson, 1981	1.50E-03	1.00E-03	7.00E-04	Read from graph. Note that the failure increases significantly beyond 35 years.
Circuit breakers	Godfrey, 1996	9.00E-02	9.95E-02	1.06E-01	Based on Weibull distribution and 10th year and terminal year rates

11 kV	Steed, 1986	2.00E-04	4.30E-04	1.10E-03	Read from graph
Recloser	Godfrey, 1996	1.50E-02	1.73E-02	1.88E-02	Based on Weibull distribution and 10th year and terminal year rates
Fuses					
Overhead	Godfrey, 1996	3.00E-03	3.00E-03	3.00E-03	Based on Weibull distribution and 10th year and terminal year rates
Transformers					
Substation power transformers					
Overhead Pole mounted	Godfrey, 1996	3.00E-03	3.87E-03	4.50E-03	Based on Weibull distribution and 10th year and terminal year rates
Overhead Pole mounted	Godfrey, 1996	5.00E-03	5.92E-03	6.53E-03	Based on Weibull distribution and 10th year and terminal year rates
Overhead Pole mounted	Steed, 1986	1.10E-05	4.90E-05	1.70E-04	Read from hazard rate graph
11kV/415V pole mounted	Freeman, 1996	1.60E-05	1.15E-04	8.09E-04	Based on a Gumbel distribution fitted to data from 181,000 UK transformers
Pad-mounted	Godfrey, 1996	2.00E-03	2.83E-03	3.46E-03	Based on Weibull distribution and 10th year end terminal year rates
Pad-mounted	Godfrey, 1996	3.00E-03	3.87E-03	4.50E-03	Based on Weibull distribution and 10th year and terminal year rates
Pad-mounted	Steed, 1986	1.00E-06	1.50E-05	1.25E-04	Read from hazard rate graph

15kV	Willis, 2001(2)	7.00E-03	4.50E-02	1.50E-01	Read from an ABB graph
15kV	Horton, 1991(1)	3.10E-03	3.20E-03	3.30E-03	Calculated based on a failure rate of the form f(t)=Kt^n, w. K=.003 and n=0
25kV	Willis, 2001(2)	1.20E-02	3.20E-02	6.00E-02	Read from an ABB graph
Submersible	Godfrey, 1996	3.00E-03	3.87E-03	4.50E-03	Based on Weibull distribution and 10th year and terminal year rates
Submersible	Godfrey, 1996	3.00E-03	3.87E-03	4.50E-03	Based on Weibull distribution and 10th year and terminal year rates
Other					
Arrester, lightning	Godfrey, 1996	2.00E-04	3.87E-04	5.70E-04	Based on Weibull distribution and 10th year and terminal year rates

Target:
Distribution Systems

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

EPRI. Electrify the World

Printed on recycled paper in the United States of America

1001873

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Distribution System Component Failure Rates and Repair Times – An Overview

Fredrik Roos
Lund University, Sweden
fredrik.roos@iea.lth.se

Sture Lindahl
Lund University, Sweden
sture.lindahl@iea.lth.se

Abstract: This paper presents the results of a literature search for publications containing failure rates and repair times, based on operational experience, for distribution system components that are critical to the reliability of a distribution system. Furthermore, component failure rates found are compared with the conclusions drawn from a previously conducted literature search.

INTRODUCTION

The awareness among electric utilities around the world of the importance of collecting and analyzing component failure and repair data increases for each year. By incorporating reliability considerations in the system design and in the planning of system expansion, operation and maintenance the quality of supply can be improved. To obtain useful results from system reliability assessments, reasonable values of component reliability parameters need to be used. However, the required accuracy of the reliability data depends on the purpose of the assessment, i.e., more accurate parameter values are required when determining actual system performance than when comparing different system configurations.

For utilities participating in national statistics co-operations, databases of failure and repair statistics are easily accessed. However, researchers at universities and those utilities that have insufficient historical performance data on their own components have to rely on published component reliability data. This published data may or may not be representative for the system under study. Thus, before trusting any results obtained from a reliability study based on published reliability data, it is advisable to perform a sensitivity analysis of the results to component reliability parameters.

Component failure rates and repair times are obtained by observation of a population. Usually the long-term average annual failure rate, λ, calculated as

$$\lambda = \frac{\text{number of failures}}{\text{number of components considered} \cdot \text{number of years of recorded data}},$$

is used in distribution system reliability analysis. The failures are divided into sustained failures and temporary failures. Sustained failures require some kind of repair work to restore the function of the component, while temporary failures will clear themselves if the component is de-energized, the fault location is de-ionized and then the component is re-energized.

The causes of component failures are due to a variety of factors such as:

- weather conditions (storms, lightning, snow, ice, outdoor temperature and air humidity),
- contamination,
- vegetation,

- animals,
- humans,
- excessive ambient temperature,
- moisture,
- excessive load,
- lack of maintenance,
- ageing,
- wear out,
- design and
- manufacture.

These factors make the component failure rates vary with time and location. Therefore, it is sometimes not accurate enough to assign identical average failure rate values to all components of a particular type. Ideally, each component is treated as an individual with a unique failure rate. However, by considering information sources providing average failure rate values valid for a variety of conditions ranges within which it is reasonable to expect the average failure rates to vary can be derived. Note, that the causes of incorrect behaviour of protection and control systems and of circuit breakers are somewhat more complicated, Heising et al. (1994), Kjølle et al. (2003) and Johannesson, Roos and Lindahl (2004).

Generally, the repair time is defined as the time it takes to restore component operation after a permanent failure of the component. The repair time can be decomposed into the following portions: The time required to get to the site, for switching operation and application of safety earthing, analyse the failure, obtain spare parts, repair and return the component to service. In addition, deliberate delays might be included. It is common practice to distinguish between repair time and restoration time. The restoration time is generally defined as the time it takes to restore customer service after a permanent failure on a component. There are three ways to restore customer service after a permanent failure in a radial distribution system: through (1) component repair, (2) component replacement or (3) switching operations. However, the definitions of the repair time and the restoration time are not as well established as the definition of the failure rate. Furthermore, other terms such as down time may occur. Therefore, it is appropriate to define the time parameters for each occasion.

The purpose of this paper is twofold. The primary purpose is to present the results of a literature search for publications containing distribution system component failure rates and repair times, based on operational experience, that can be useful in distribution system reliability studies. So far, there are two comprehensive reviews on information sources providing distribution system component reliability data, Bollen (1993) and Brown (2002). In addition to component reliability information based on operational experience, both these previously conducted literature reviews considered recommended values found in book and standards and values used in reliability studies. The references in Bollen (1993) were published during the period from 1957 through 1992, with a majority of the references published during the 1980s. Therefore, this paper considers information sources published during the recent decade between 1993 and 2003. The secondary purpose is to investigate if the recently published information sources indicate that the failure rate values suggested in Bollen (1993) still holds.

COMPONENT RELIABILITY DATA BASED ON OPERATIONAL EXPERIENCE

CIGRE 13.06 Working Group has conducted two worldwide reliability surveys of the reliability of high-voltage circuit breakers in the voltage range 63 kV and above. Reference Heising et al. (1994) summarizes the most significant reliability data from the two surveys. A distinction is made between major failures and minor failures. A major failure occurs when the breaker can no longer perform all of its fundamental functions, or when intervention within 30 minutes is necessary. All other failures are referred to as minor failures. The circuit breaker down time is defined as the time from the discovery of the failure until the breaker is returned to service, excluding deliberate delays. For single-pressure SF6 breakers installed at voltage levels 63-99 kV the second survey comprises 24,355 breaker-years. Table 1 shows some of the results from the second survey covering the years 1988 through 1991.

Table 1 *Major failure rate, minor failure rate and down time for major failures that are presented in Heising et al. (1994).*

component	major	minor	down time	
			average	median
circuit breakers (63-99 kV, single-pressure SF6)	0.3 / (100 breakers, year)	2.2 / (100 breakers, year)	39.1 hrs	24.0 hrs

In Lauronen and Partanen (1997) 8,000 km of MV rural distribution systems located in Finland is studied. The work is based on all the sustained failures that occurred on the MV distribution systems under study during the period from 1989 through 1995. The paper presents the average sustained failure rates and the maximum annual sustained failure rates for the period of study as shown in Table 2.

Table 2 *Average sustained failure rates and maximum annual sustained failure rates presented in Lauronen and Partanen (1997).*

component	average	maximum
pole mounted transformers (< 315 kW, spark gap protected)	0.5 / (100 transformers, year)	1.0 / (100 transformers, year)
overhead lines (including insulator and cross arm failures)	0.93 / (100 km, year)	1.81 / (100 km, year)
poles (impregnated wood)	0.084 / (100 km, year)	0.223 / (100 km, year)

Reference Maciela et al. (1999) reports on the French experience with the reliability performance of MV polymer housed surge arresters that have been installed since 1992. The population studied consisted of about 800,000 units. Table 3 shows the average failure rate of these MV polymer housed surge arresters.

Table 3 *Average failure rates of MV polymer housed surge arresters that have been installed in France since 1992, presented in Maciela et al. (1999).*

component	average
surge arresters (MV, polymer housed)	0.03 / (100 arresters, year)

In Shwehdi et al. (2000) reliability data on industrial transformers is presented as shown in Table 4. The data was recorded between 1995 and 1998 from observations of the performance of transformers in operation at voltage levels between 2.5 and 35 kV in six different plant locations in the eastern region of Saudi Arabia. The population studied consisted of 6353 units.

Table 4 *Average failure rates and average repair and replacement time presented in Shwehdi et al. (2000).*

component	average	repair and replacement time
industrial transformers (2.5-35 kV, liquid filled)	0.5 / (100 transformers, year)	308.9 hrs

In Statnett (2002) average temporary and sustained failure rates for power system components in Norway, for the period 1993 through 2002, are presented as shown in Table 5.

Table 5 *Average temporary and sustained failure rates presented in Statnett (2002).*

component	temporary	sustained
overhead lines (33-110 kV)	1.04 / (100 km, year)	0.5 / (100 km, year)
underground cables (33-110 kV)	0.15 / (100 km, year)	0.95 / (100 km, year)
power transformers (33-110 kV)	0.4 / (100 transformers, year)	0.6 / (100 transformers, year)
protection and control for power transformers (33-110 kV)	0.9 / (100 transformers, year)	0.6 / (100 transformers, year)

In addition to average failure rates, the cumulative distributions of the repair time for various power system components are presented in Statnett (2002). In general, repair times differ significantly, even for components of the same type, which results in a large value of the standard deviation of the repair times for components of a particular type. Consequently, the mean value of the component repair times cannot be considered as a "representative" value of the component repair time. Despite this inadequacy of the mean values of the component repair times given in Statnett (2002), the mean component repair times, based on repairs carried out in Norway during the period 1993-2002, are shown in Table 6.

Table 6 *Mean component repair times, based on repairs carried out during the period 1993-2002, presented in Statnett (2002).*

component	mean repair time
overhead lines (33-110 kV)	54 hrs & 1 min
underground cables (33-110 kV)	127 hrs & 55 min
power transformers (33-110 kV)	115 hrs & 59 min
protection and control for power transformers (33-110 kV)	14 hrs & 48 min
circuit breakers (33-110 kV)	52 hrs & 1 min

CONCLUSIONS

The authors´ experience is that the amount of published distribution system component reliability data, based on operational experience, is quite limited. Though, reliability data, published during the period 1993 through 2003, has been found on the following distribution system components that are critical to the reliability of a distribution system.

- overhead lines,
- underground cables,
- circuit beakers,
- pole mounted transformers,
- power transformers,
- surge arresters and
- protection and control systems.

The sustained failure rates for MV/MV transformers published during the recent decade indicate a variation of the average transformer failure rates in the range 0.4-1 failures / (100 transformers, year). As a comparison the transformer failure rate ranges suggested in reference Bollen (1993) are given below.

MV/LV transformers:	0.1-0.2 / (100 transformers, year)
MV/MV transformers:	1-1.3 / (100 transformers, year)
HV/MV transformers:	1.4-2.5 / (100 transformers, year)

Reference Statnett (2002) report on a sustained underground cable failure rate of 0.95 failures / (100 km, year), while reference Bollen (1993) suggests the underground cable failure rate range 1.3-2.5 failures / (100 km, year).

Transformer and cable failure rates published during the recent decade indicate somewhat lower values than the suggested values in reference Bollen (1993).

DISCLAIMER

The authors have done their best in providing an overview of the available information sources, published during the period 1993-2003, on distribution system component failure rates and repair times derived from historical component performance data. However, it is very likely that there is relevant literature that has not been given the attention it deserves. The authors are aware of the existence of the following publications, which have not been available to the authors due to a limited budget.

Verlo, T.; Lundgaard, L. and Faremo, H.: "Failure Statistics of Mass Impregnated Cables, Joints and Terminations", Technical Report, TR A4432, SINTEF Energy Research, June 1996.

Gjærde, A. C.; Lundgaard, L. and Faremo, H.: "Feilstatistikk for massekabel, endeavslutninger og skjøter 1991-1995", Technical Report, TR A4540, SINTEF Energy Research, May 1997. (in Norwegian)

Worth mentioning is the IEEE standard 493-1997. This standard is a revised version of the IEEE standard 493-1990, which has been included in the literature reviews Bollen (1993) and Brown (2002). IEEE standard 493-1997 provides a summary of electrical equipment reliability data obtained from extensive IEEE surveys.

REFERENCES

Bollen, M. H. J.: "Literature Search for Reliability Data of Components in Electric Distribution Networks", Technical Report, EUT 93-E-276, Eindhoven University of Technology, August 1993.

Brown, R. E.: "Electric Power Distribution Reliability", Section 4.5, pp. 134-141, New York: Marcel Dekker, 2002.

Heising, C. R.; Janssen, A. L. J.; Lanz, W.; Colombo, E. and Dialynas, E. N.: "Summary of CIGRE 13.06 Working Group World Wide Reliability Data and Maintenance Cost Data on High Voltage Circuit Breakers Above 63 kV", Conference Record, Vol. 3, pp. 2226-2234, 1994 IEEE Industry Applications Society Annual Meeting, October 2-6, 1994, Denver.

Johannesson, T.; Roos, F. and Lindahl, S.: "Reliability of Protection Systems – Operational Experience 1976-2002", Conference Proceedings, Vol. 1, pp. 303-306, Eighth IEE International Conference on Developments in Power System Protection, April 5-8, 2004, Amsterdam.

Kjølle, G. H.; Heggset, J.; Gjerde, O. and Hjartsjø, B. T.: "Feilstatistikk for vern, kontroll- og automatiseringsutstyr 1-420 kV", Technical Report, TR A5739, SINTEF Energy Research, February 2003. (in Norwegian)

Lauronen, J. and Partanen, J.: "The Fault Rate of Electrical Distribution Network Components in Different Weather Conditions and in Different Seasons of the Year", Conference Proceedings, Power Quality Applications '97 Conference, June 15-18, 1997, Stockholm.

Maciela, F.; Le Roux, P.; Gazzola Ferraz, C.; Malpiece, F. and Tartier Sediver, S.: "French Service Experience with MV Polymer Housed Surge Arresters", Conference Proceedings, Fifteenth CIRED International Conference on Electricity Distribution, June 1-4, 1999, Nice.

Shwehdi, M. H.; Bakhashwain, J. M.; Farag, A. S. and Assiri, A. A.: "Distribution Transformers Reliability; Industrial Plant in Saudi Arabia", Conference Proceedings, Vol. 4, pp. 2769-2774, 2000 IEEE Power Engineering Society Winter Meeting, January 23-27, 2000, Singapore.

Statnett (2002): "Driftsforstyrrelser i 33-420 kV nettet – Årsstatistikk 2002", Statnett. (in Norwegian)

Exhibit 2

Exponent®

Engineering Sciences

LUMA FY 2024 Reliability Performance Assessment

Exponent®

LUMA FY 2024 Reliability Performance Assessment

Prepared for:

LUMA

Prepared by:

Exponent Inc.
149 Commonwealth Drive
Menlo Park, CA 94025
rbrown@exponent.com

March 17, 2025

Contents

Limitations

At the request of LUMA, Exponent conducted an assessment of the reliability performance of the LUMA transmission and distribution system for FY2024, with a focus on the reported value of SAIDI as compared to the reported value of SAIDI in FY2023. The results and conclusions of this evaluation are based on the information supplied by LUMA and public records. The opinions and comments formulated during this assessment are based on observations and information available at the time of this assessment.

The findings presented herein are made to a reasonable degree of engineering certainty. If new data becomes available or there are perceived omissions or misstatements in this report regarding any aspect of those conditions, we ask that they be brought to our attention as soon as possible so that we have the opportunity to fully address them.

1. Executive Summary

The Puerto Rico Energy Bureau (PREB) recently issued a resolution and order stating that LUMA is in noncompliance with its SAIDI metric, stating that SAIDI for FY2024 is significantly higher than both FY2023 and the baseline year of FY2020. This order required LUMA, among other things, to explain the root causes of the indicated noncompliance and any mitigating factors. Exponent was retained to perform an assessment of LUMA's reliability performance to address this requirement.

The assessment was primarily based on outage management data which provides raw data for every outage event, such as start time, end time, cause code, customers interrupted (CI), and the associated number of customer interruption minutes (CMI). Data was provided for fiscal years 2019 through 2024, where FY2019 through FY2021 were with the T&D system being operated by PREPA and FY2022 through FY2024 were with the system being operated by LUMA. An assessment of this data results in the following conclusions:

1. SAIDI during the LUMA years (FY2022 through FY2024) has stayed essentially constant if the major event days associated with Hurricane Fiona are properly considered. After adjusting for Fiona, FY2024 shows a slight increase of 3.8% when compared to FY2023 but a slight *decrease* of 7.1% when compared to FY2022. These three years, taken together, show a slightly improving SAIDI trend.

2. A comparison of reported SAIDI during the LUMA years to the baseline year of FY2020 is misleading for several reasons. First, PREPA was not recording a significant number of secondary outages, making reported SAIDI artificially low. Second, weather severity in FY2020 was mild when compared to all other years considered. Adjusting FY2020 for these factors so that a fair comparison with FY2024 can be made would require an increase of 1.5% to account for underreported secondary outage events and an increase of 9.5% to account for weather severity. This results in an upward adjustment of the FY2020 baseline SAIDI value of 11%, bringing it up from 1,243 minutes to 1,380 minutes. This compares to the reported SAIDI for FY2024 of 1,432 minutes, which is a 3.8% increase.

3. However, LUMA has also implemented needed safety practices that resulted in an increased average SAIDI of 12.5%. If LUMA is not to be penalized for implementing these safety practices, reliability, not considering these safety practices actually improved by about 8.7% (12.5% - 3.8%) when compared to the baseline year.

And so, SAIDI has gotten slightly worse if safety practices are not accounted for and moderately better if safety practices are accounted for. This is true even as the total number of outage events has significantly increased, largely due to more severe weather and increasing vegetation-related outages.

Based on its reliability assessment, Exponent has assessed the appropriateness of LUMA's Corrective Action Plan (CAP). It was determined that the proposed LUMA CAP is appropriate for effectively managing SAIDI and, if fully implemented, should result in a downward SAIDI trend. These benefits are especially dependent upon the successful implementation of a cycle-based vegetation management program for both transmission and distribution, as vegetation-related outages have been significantly increasing in recent years.

2. Introduction

On February 11, 2025, the Puerto Rico Energy Bureau (PREB) issued a resolution and order stating that LUMA is in noncompliance with its SAIDI metric (Case No. NEPR-AI-2025-0001). The order reads:

> *Following a review of LUMA's FY24 performance report, SAIDI results for this period were worse than those reported for the previous year, indicating a decline in service reliability. Specifically, for FY24, LUMA reported an annual system SAIDI value for the combined transmission and distribution system of 1,432 minutes ... This is a deterioration over LUMA's FY23 performance of 1,218 minutes, and a worsening of 89 minutes relative to the FY20 baseline of 1,243 minutes... As a result of this worsening reliability, and noncompliance with Puerto Rico's energy policy, the Energy Bureau is compelled to issue a Notice of Noncompliance to ensure corrective action. Given the severity of the situation a fine is necessary to counteract this negative trend in outage duration and ensure compliance with performance standards.*

The PREB ordered LUMA to respond within twenty days to this notice (an extension has since been granted). This response must include the following:

1. A Corrective Action Plan detailing the measures to be implemented to improve SAIDI and prevent further deterioration of service quality.
2. Justification explaining the root causes of the noncompliance and any mitigating factors.
3. The information listed in Section 14.03 of Regulation 8543.

This report primarily addresses Item 2 above, and to a certain extent, Item 1 based on the analyses performed for Item 2. This report has been developed under a short timeline, which is insufficient to include a comprehensive and specific detailed corrective action plan.

3. Reliability Data

Reliability data used for this assessment is from the LUMA interruptions database, which provides raw data for every outage event such as start time, end time, cause code, customers interrupted (CI), and the associated number of customer interruption minutes (CMI). Data has been provided for fiscal years 2019 through 2024.

LUMA is required to report, among other things, the reliability indices SAIFI and SAIDI to the PREB. SAIFI is equal to the total CI over a period of time divided by the total number of customers served during this period. Similarly, SAIDI is equal to the total CMI over a period of time divided by the total number of customers served during this period. For this analysis period of fiscal years 2019 through 2024, LUMA has calculated SAIFI and SAIDI using the same customer count of 1,468,223. Therefore, CI and CMI values for each of the fiscal years are directly comparable to each other, and the analyses would be identical using either SAIFI/SAIDI or CI/CMI. Since the raw data is in CI and CMI, the analyses in this report will primarily use CI and CMI. In addition, since the PREB resolution and order only addresses SAIDI, this report primarily focuses on an assessment of CMI.

LUMA reports SAIDI according to IEEE Standard 1366. This standard includes a statistical methodology to identify Major Event Days (MEDs). These days are excluded when calculating reliability indices. These MEDs have, therefore, been excluded from the data provided from which the analyses in this report are based.

This said, the following table shows the number of MEDs excluded in the assessed fiscal years:

Table 3-1. MEDs by Fiscal Year

Fiscal Year	Total	Fiona	Other
FY2024	5		
FY2023	39	37	2
FY2022	9		
FY2021	5		
FY2020	4		
FY2019	2		

Without including FY2023, the number of MEDs in a given fiscal year range from 2 to 9. This is in stark contrast to FY2023, which has 39 MEDs, 37 of which are due to Hurricane Fiona (Fiona). This is important because a large number of days in FY2023 do not contribute anything to reported SAIFI and SAIDI. To give an extreme example, consider a situation where an entire year was classified as a major event such that all days were excluded from reported reliability indices. In this case, both SAIFI and SAIDI would be zero, indicating that customers experienced no service interruptions on non-MEDs. This is correct as far as it goes, but highly misleading as customers certainly did not experience zero interruptions. It is simply not appropriate to directly compare a year with many MEDs excluded a year with few MEDs excluded.

In FY2023, Fiona resulted in 37 MEDs, which represents 9.8% of the total number of days in a year. If reliability is similar for all days over a year, FY2023 would report SAIFI and SAIDI values about 9.8% lower than would be expected if Fiona had not occurred. It is, therefore, inappropriate to compare other years with FY2023 without taking the impact of Fiona into account. The following section in this report performs an assessment as to how the reliability of FY2023 can be fairly adjusted to reflect what it would likely have been had Fiona not occurred.

4. Hurricane Fiona

In FY2023, Hurricane Fiona resulted in 37 MEDs, which represents 9.8% of the total number of days in a year. If reliability is similar for all days over a year, FY2023 would report SAIFI and SAIDI values about 9.8% lower than would be expected if Fiona had not occurred. It is, therefore, inappropriate to compare other years with FY2023 without taking this into account. What is needed is to fairly adjust the reliability metrics of FY2023 to reflect what it would likely have been had Fiona not occurred.

An adjustment must consider the fact that expected daily reliability will be different throughout the year based on typical weather patterns. Therefore, the FY2023 adjustment uses a 30-day moving average approach that can account for this weather variation. Specifically, historical data from FY2022 through FY2024 was used to create a mathematical model of expected daily reliability. This process fitted the following function based on the minimum least squared error (MLSE) method:

$$SAIDI_{PRED} = e^{fx} * (1 - a\sin(cx + d) + b) + e^{kx} * (g\ sin(ix + j) + h)$$

The following figure shows the 30-day moving average and the function that fits these data points with the MSLE:

Figure 4-1. Curve Fit for Expected Daily Reliability

The dip in the blue line in Figure 4-1 is due to the excluded MEDs due to Fiona. The orange curve during this period is the expected daily SAIDI values had Fiona not occurred. Reported SAIDI for FY2023 was 1,218 minutes. The expected additional SAIDI that would have occurred during the Fiona-related MEDs had Fiona not occurred is 160 minutes, or an increase of 13.1%. Therefore, all the analyses in this report will increase CMI, SAIDI, and outage event values related to FY2023 by 13.1% so that it can be compared more meaningfully to other years and more meaningfully review trends. This is referred to as the Fiona Adjustment.

A graph showing the impact of the Fiona Adjustment is shown in Figure 4-2. Data behind this graph is shown in Table 4-1. The orange line (labeled CMI-ADJ) shows CMI for each fiscal year with the Fiona Adjustment. The blue line shows (labeled CMI) CMI for each fiscal year without the Fiona Adjustment. As can be seen, CMI increases from FY2023 to FY2024 in both cases, but much less dramatically with the Fiona Adjustment.

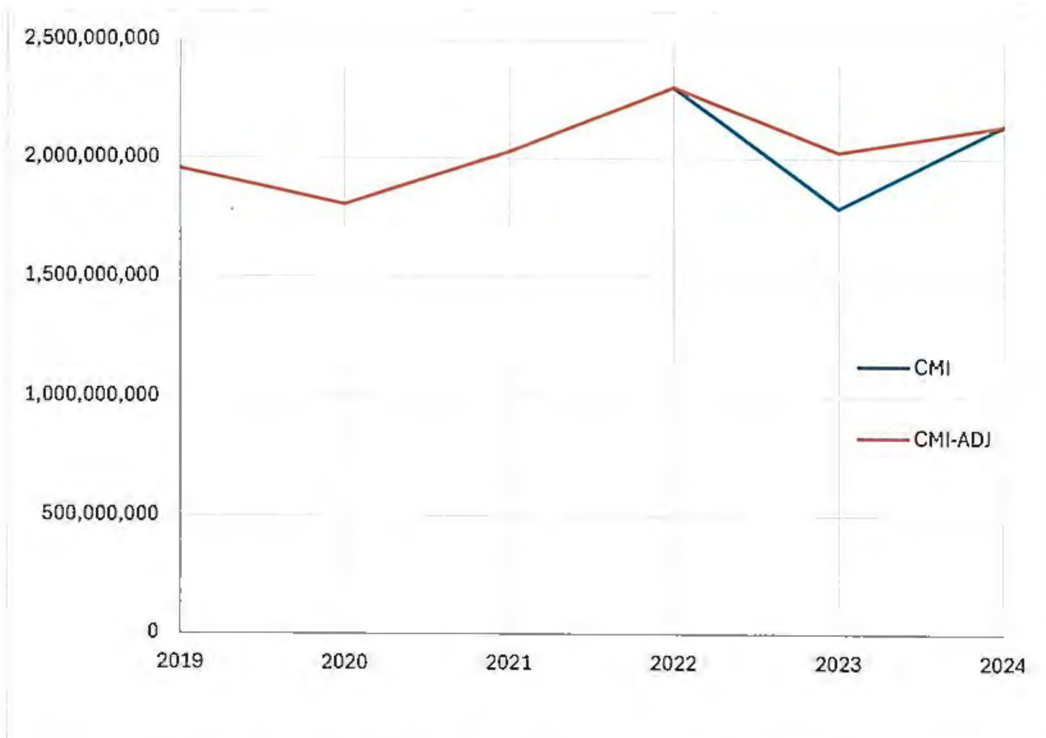


Figure 4-2. Impact of Hurricane Fiona Adjustment

Table 4-1. CMI with and without the Fiona Adjustment

Fiscal Year	CMI	CMI-ADJ
2019	1,954,800,622	1,954,800,622
2020	1,805,242,780	1,805,242,780
2021	2,025,650,516	2,025,650,516
2022	2,299,552,165	2,299,552,165
2023	1,790,171,976	2,025,579,591
2024	2,137,249,691	2,137,249,691

The adjusted and unadjusted values for FY2023 and FY2024 are (values are slightly different than reported values since they have been calculated directly from raw data):

SAIDI FY2023 Unadjusted:	1,218
SAIDI FY2024:	1,431
Change:	+17.5%

SAIDI FY2023 Adjusted:	1,378
SAIDI FY2024:	1,431
Change:	+3.8%

As can be seen, the reported numbers show an increase in SAIDI from FY2023 to FY2024 of 17.5%. However, this is an improper comparison in terms of reliability performance due to the excluded Fiona MEDs in FY2023. A fair comparison using the Fiona Adjustment for FY2023 shows a small increase of 3.8%. To the extent the PREB is considering the SAIDI increase from FY2023 to FY2024 in its actions against LUMA, there should be a clear understanding that those actions would be based on a 3.8% increase rather than a 17.5% increase.

Hurricane Fiona represents an extreme case where data needs to be adjusted due to weather for fair comparisons with other years to be made. This said, severe weather throughout the year that does not reach the threshold of a MED can also significantly impact reliability and should be considered for proper comparisons to be made. This aspect of reliability is addressed in the next section.

5. Minor Storms

A day during a severe weather event that results in it being excluded according to the IEEE 1366 MED exclusion criteria is called a Major Event Day (MED). There are also days that have severe weather that results in many outages that may not be excluded according to the IEEE 1366 MED exclusion criteria. This section refers to these Minor Storm Days. LUMA documentation sometimes refers to Minor Storm Days as Gray Sky Days (GSD). The number and severity of Minor Storm Days in any given fiscal year can vary greatly, which will also cause reliability indices such as SAIDI to vary greatly. It is therefore important to understand if changes in SAIDI are due to inherent reliability changes or due to differences in weather conditions.

The specific criteria that LUMA uses to identify a Minor Storm Day are as follows. First, the National Oceanic and Atmospheric Administration (NOAA) must have issued a severe weather warning for one or more locations in Puerto Rico. Second, the system must have been severely impacted as determined by either (A) more than 150 outage events having occurred during the day; or (B) the maximum number of customers simultaneously interrupted during the day exceeds the sum of 20,500 plus the average daily maximum for the previous 30 days.

CMI Values showing totals and breakdowns based on minor storm days are shown in Table 5-1. The total corresponds to the reported SAIDI (FY2023 has been adjusted to account for Fiona). OE corresponds to days with NOAA severe weather warnings where the customer threshold is exceeded. OJ refers to days with NOAA severe weather warnings where the number of outage jobs is exceeded. MS is the CMI due to minor storms. It includes days that are either an OE day, an OJ day, or both.

Table 5-1. CMI Due to Minor Storms

	CMI						
Fiscal Year	Total	OE	OJ	MS	OE	OJ	MS
2019	1,954,800,622	654,165,159	109,720,177	654,165,159	33.5%	5.6%	33.5%
2020	1,805,242,780	459,427,925	210,246,279	488,208,349	25.4%	11.6%	27.0%
2021	2,025,650,516	598,167,408	260,517,885	630,242,602	29.5%	12.9%	31.1%
2022	2,299,552,165	636,286,783	323,195,301	727,724,844	27.7%	14.1%	31.6%
2023	2,025,579,591	557,291,451	451,910,107	688,046,919	27.5%	22.3%	34.0%
2024	2,137,249,691	544,049,120	606,662,309	776,728,957	25.5%	28.4%	36.3%

The final column in Table 5-1 shows the percentage of CMI due to Minor Storm Days. As can be seen, FY2020 has the lowest percentage at 27.0%, and FY2024 has the highest percentage at 36.3%. This means that FY2020 had relatively mild weather in terms of minor storms, and FY2024 had relatively severe weather in terms of minor storms. It is, therefore, appropriate to consider this when comparing FY2024 SAIDI to the baseline values based on FY2020.

An adjustment can be made by reducing the percent contribution of minor storm days to CMI/SAIDI to that of the baseline year. For example, the contribution of minor storm days to FY2024 CMI/SAIDI is 36.3%. This contribution can be reduced by 9.3% so that its contribution is 27.0%, the same as the baseline year. The resulting CMI/SAIDI value is what would be expected if the weather severity in terms of minor storm days were the same in FY2024 as in FY2020.

A graph showing minor-storm-day-adjusted (MSDA) CMI and unadjusted CMI is shown in Figure 5-1. The blue line shows unadjusted data (labeled CMI), and the orange line shows MSDA data (labeled CMI-ADJ). As can be seen, the lines have the same value for FY2020, as this is the baseline year to which other years are adjusted. All the other years had more severe weather than FY2020 and are therefore adjusted downward to reflect what CMI would have been if the weather had been similar to FY2020.

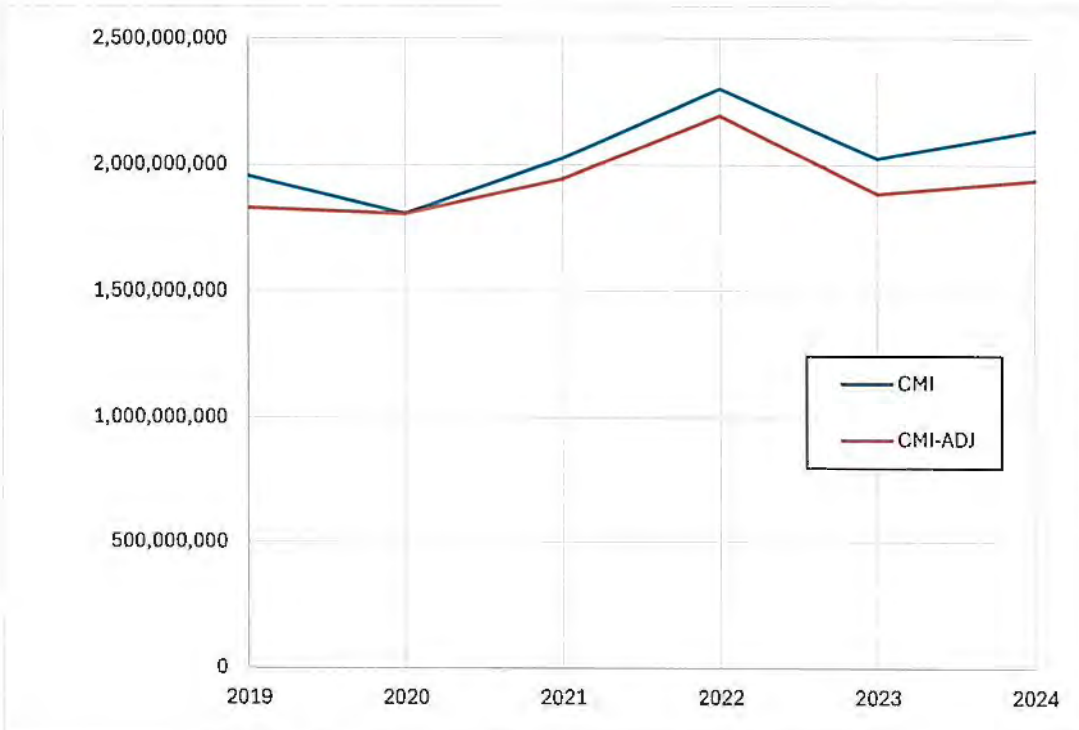


Figure 5-1. Impact of Minor Storm Day Adjustment

The adjusted and unadjusted values for FY2020 and FY2024 are:

CMI FY2020:	1,230
CMI FY2024:	1,456
Change:	+18.4%

SAIDI FY2020:	1,230
SAIDI FY2024 Adjusted:	1,320
Change:	+7.3%

As can be seen, the reported numbers show an increase in SAIDI from FY2020 to FY2024 of 18.4%, but this is an improper comparison in terms of reliability performance due to FY2020 being a mild weather year and FY2024 being a severe weather year. Making a comparison based on unadjusted numbers would, in part, be penalizing LUMA based on bad weather.

A fair comparison using the MSDA adjustment method for FY2024 shows an increase of 7.3%. To the extent the PREB is considering the SAIDI increase from FY2020 to FY2024 in its actions against LUMA, it should use an increase of 7.3% rather than an increase of 18.4%.

6. PREPA Data Versus LUMA Data

Up to this point, adjustments have been made to account for the absence of MEDs in reported reliability and variations in weather severity from year-to-year. Still, it is not clear whether the data from the baseline year is an "apples to apples" comparison in terms of data. Outage data was collected by PREPA in FY2019, FY2020, and FY2021 (PREPA Years). Outage data was collected by LUMA in FY2022, FY2023, and FY2024 (LUMA Years).

Outage events by cause are shown in Table 6-1. The total number of outage events in the PREPA Years ranges from 31,584 to 33,019, with an average of 32,457. The total number of outage events in the LUMA Years ranges from 38,444 to 46,266 with an average of 42,727. This represents an increase from the last PREPA Year to the first LUMA year of 6,860 (21.7%) and an average increase from the PREPA Years to the LUMA Years of 10,271 (31.6%). Given that the total number of outages in the PREPA years was essentially holding constant, the large increase seen in the LUMA Years cannot be due to actual outages increasing by this amount. Rather, the large increase seen in the LUMA Years compared to the PREPA years is likely due, at least in a substantial amount, to different data collection practices. The increase in outages due to data collection practice changes from PREPA to LUMA is referred to as a Step Change.

Table 6-1. Outage Events by Cause

	Events											
FY	Total	Lightning	Weather	Unknown	Cont.	Equip.	Other	Planned	Supply	Public	Veg.	Wildlife
2019	32,767	0	5,972	6,113	0	10,897	445	0	75	27	6,464	2,774
2020	33,019	0	5,785	5,738	0	10,821	356	0	47	23	7,834	2,415
2021	31,584	0	4,404	6,034	0	10,489	312	0	56	19	8,097	2,173
2022	38,444	383	4,430	6,367	0	14,627	448	0	62	112	9,131	2,884
2023	43,473	2,323	3,442	4,942	6	15,452	929	0	40	877	11,771	3,691
2024	46,266	2,871	3,608	2,912	61	15,726	1,338	19	46	900	14,561	4,224

A closer look at the data shows that the Step Change can largely be attributed to the reporting of equipment-related outages. During the PREPA Years, recorded equipment-related outages remained stable at between about 10,500 and 11,000. The trend is actually slightly downward, which is highly unlikely to reflect the actual number of equipment-related outages during these years since PREPA had dramatically reduced equipment maintenance for many years prior.

From the last PREPA Year to the first LUMA year, reported equipment outages increased from 10,489 to 14,627 (39.5%). There is no possibility that this increase was due to equipment outages actually increasing by nearly 40%. Rather, it seems that LUMA was capturing a much higher percentage of equipment outages than PREPA. To understand this further, a breakdown of equipment-related events is provided in Table 6-2. The yellow highlighted section corresponds to equipment failures that occur on the secondary distribution system rather than on the primary distribution system.

As can be seen, there is a dramatic increase in recorded events from FY2021 to FY2022 related to secondary equipment. The total for FY2021 in the yellow-highlighted cells is 2,286, and the total for FY2022 in the yellow-highlighted cells is 5,210. This indicates that PREPA was recording less than half of equipment-related secondary outages in their OMS. Crews would address secondary outages and often not relay the information such that it would be entered into the OMS system. For this reason, SAIDI and CMI experienced in the PREPA years cannot be fairly compared to SAIDI and CMI experienced during the LUMA years since more complete outage information is being collected by LUMA. This more complete outage information results in a higher reported SAIDI than would otherwise be reported if data collection had not improved.

Table 6-2. Breakdown of Equipment Failure Cause Codes

Equipment Failure Cause Code	Fiscal Year					
	2019	2020	2021	2022	2023	2024
115 kV Transmission Line Source					14	29
230 kV Transmission Line Source					1	2
38 kV Transmission Line Source					96	202
Broken / Rusty Hardware	46	54	53	98		
Capacitor Failure					3	
Connector Failure						54
Cutout Failure	1,877	1,993	1,981	2,381	2,408	2,875

Equipment Failure Cause Code	Fiscal Year					
	2019	2020	2021	2022	2023	2024
Defective Control Device	1	6	4	1		
Defective Pole	587	525	531	484		
Distribution Substation Bus Support				4	14	22
Feeder Breaker Failure	39	47	17	38	78	62
Insulator/ Pin Failure	587	656	655	906	653	841
Lightning Arrester Failure	244	230	224	379	386	379
Load Shed (Contingency) - Transmission						1
Open Jumper						806
Pole Breaker Failure				1	3	3
Power Transformer Failure	5	9	5	10	18	9
Primary Crossarm Failure				21	87	107
Primary Pole Failure				56	490	525
Primary To Primary Contact				63	536	521
Primary Wire Break				497	3,185	2,665
Regulator Failure					4	2
Secondary Defective Pole	140	96	96	229		
Secondary Other Equipment				9	90	134
Secondary Pole Failure				23	147	163
Secondary To Secondary Contact				45	204	195
Secondary Wire Break				382	3,249	3,861
Secondary Wire Down	1,244	1,156	1,174	3,232		
Service Transformer Failure	1,173	1,205	1,016	1,290	1,144	1,353
Switch Failure	348	319	269	341	245	236
UG - Broken Splice / Terminal	319	254	224	211		
UG Cable Fault	371	356	302	418	310	334
UG Cable Splice Failure				10	23	34
UG Cable Termination Failure				28	144	212
UG Switching Unit Failure	67	81	78	93	124	99
Wire Down	3,849	3,834	3,860	3,377		
Total	**10,897**	**10,821**	**10,489**	**14,627**	**13,656**	**15,726**
Secondary Equipment	2,557	2,457	2,286	5,210	4,834	5,706

It is apparent that LUMA is capturing more complete outage data as compared to PREPA. Although this is good in the sense of better understanding reliability performance, it results in reported SAIFI and SAIDI being higher than what they would otherwise be, if data collection had been comparable to what it was in the PREPA years.

The average CMI impact over from FY2019 through FY2024 for secondary-related events is 6,620. This has been determined by dividing the total amount of CMI for all secondary-related events by the total number secondary-related events. If the baseline year failed to report 4,000 secondary-related events, its total CMI would be increased by 26,480,368, an increase of 1.5%

The CMI values (with and without the Fiona adjustment) from Table 4-1 are repeated here as Table 6-3.

Table 6-3. CMI with and without the Fiona Adjustment

Fiscal Year	CMI	CMI-ADJ
2019	1,954,800,622	1,954,800,622
2020	1,805,242,780	1,805,242,780
2021	2,025,650,516	2,025,650,516
2022	2,299,552,165	2,299,552,165
2023	1,790,171,976	2,025,579,591
2024	2,137,249,691	2,137,249,691

This 1.5% impact due to data collection is statistically identifiable, but the impact of better data collection is likely much higher than this. For example, when utilities in the mainland U.S. started to transition from manual outage data collection to automated outage management systems, it was not uncommon for SAIDI to increase by as much as 50% to 100%. Actual customer reliability was unchanged, but more complete outage data collection resulted in much higher SAIDI values that were not directly comparable to previous years. But since identifying and quantifying the full impact of better data collection requires an extensive amount of time and effort, this analysis will only consider the impact of better data collection with regard to secondary-related events.

As can be seen, CMI values (and therefore SAIDI) increased significantly from FY2021 (the last PREPA year) to FY2022 (the first LUMA year). It is known that some of this increase is due to better data collection, especially with regard to secondary equipment failures. But it is also likely that some of this increase is due to operational changes engaged by LUMA to increase safety. This includes a culture change for linemen responding to outages to "slow down" and take the time to complete the expected safety protocols. LUMA experienced a CAIDI increase after implementing these changes from about 160 minutes to 180 minutes, corresponding to an increase of 12.5%. It is likely that a majority of this increase is due to the increased focus on safety. If so, this would result in a corresponding SAIDI increase of 12.5%. Specific components of these safety enhancements include the following:

- **Equipotential Bonding and Grounding.** Developed a new and extensive work method with an expectation that time is taken to properly and effectively ground a work area before commencing work.
- **Pre-work Hazard Assessments.** Expectation that a thorough hazard assessment and corresponding hazard mitigation activities are undertaken before any work is started.
- **Job Site Tailgate Meetings**. Tailgate meetings are to review hazards/mitigations, work plan and ensure alignment of all workers on the worksite. Also, it is expected that the time is taken whenever work scope changes to have a thorough tailgate safety meeting and all workers sign-off on what was discussed.
- **Standdowns.** When significant safety events happen or a pattern of smaller events occurs, the following crews are stood down from starting work to review the immediate findings from the safety events.
- **3-way communication/PSWS.** A new phone system has been implemented that records calls into the operating centers. The expectation is that the time is taken to properly complete the 3-way communication protocol and understand the switching order before the commencement of switching.

All of the above activities will result in an increase in SAIDI, as they take time to be properly performed. However, safety should always be the highest priority, so LUMA should not be penalized to the extent that the above actions resulted in an increase in SAIDI (likely to be about 12.5%). Hypothetically, if PREPA had the above safety measures in place during the baseline year, and these safety measures resulted in a 12.5% SAIDI increase, the baseline year would have a CMI of 1,805,242,780 x 1.125 = 2,030,989,128 as compared to the FY2024 value of 2,137,249,691. This represents an increase of about 5.3% without considering the impacts of minor storms or more complete data collection.

The lack of full outage data collection during the PREPA years makes regulatory reliability baselines based on FY2020 problematic. LUMA should be expected by regulators to manage reliability in a prudent manner, but this will not be evident based on FY2020 baseline comparisons. For this reason, the following section performs a statistical assessment of reliability performance during the LUMA Years, where "apples to apples" comparisons are possible.

7. Assessment of LUMA Reliability

A summary of data for fiscal years 2022 through 2024 is shown in Table 7-1. The first thing to notice is that CMI and Events in the "Unknown" category go down drastically from FY2022 to FY2024. Unknown CMI goes from 621.2M down to 108.5M, and Unknown Events goes from 6,367 down to 2,912. These reductions show that LUMA is emphasizing the identification of outage causes, which is a good thing. However, these reductions must have been reclassified to other categories. Therefore, increases in other categories may be due to (1) reductions in the unknown category; (2) actual increases; or (3) a combination of both.

Interviews with LUMA shed some light on the issue. When LUMA took over operations, it was typical practice not to investigate the cause of an outage if a line successfully reclosed. LUMA discontinued this practice by requiring line patrols to identify likely outage causes even after a successful reclosing effort. By far, the most commonly identified cause in these situations is vegetation. Therefore, much of the increases seen in vegetation outages are due to reductions in the unknown category.

Table 7-1. LUMA Reliability Data by Cause Category

CMI (M)											
FY	Total	Lightning	Weather	Unknown	Cont.	Equip.	Other	Supply	Public	Veg.	Wildlife
2022	2,300	13.5	131.0	621.2	0.0	920.8	63.9	45.2	7.5	377.8	118.6
2023	2,026	53.5	82.2	295.8	1.0	908.6	123.4	31.3	58.6	396.0	75.3
2024	2,137	47.3	103.5	108.5	29.0	963.2	184.4	35.5	50.0	514.5	101.5

Events											
FY	Total	Lightning	Weather	Unknown	Cont.	Equip.	Other	Supply	Public	Veg.	Wildlife
2022	38,444	383	4,430	6,367	0	14,627	448	62	112	9,131	2,884
2023	43,473	2,323	3,442	4,942	6	15,452	929	40	877	11,771	3,691
2024	46,247	2,871	3,608	2,912	61	15,726	1,338	46	900	14,561	4,224

CMI per Event											
FY	Total	Lightning	Weather	Unknown	Cont.	Equip.	Other	Supply	Public	Veg.	Wildlife
2022	59,816	35,215	29,561	97,571	0	62,955	142,690	728,704	67,174	41,374	41,131
2023	46,595	23,019	23,867	59,846	183,272	58,800	132,884	790,789	66,783	33,641	20,392
2024	46,195	16,458	28,689	37,276	474,682	61,247	137,805	772,250	55,528	35,331	24,026

A common practice during the PREPA years was to first attempt to replace a blown fuse without patrolling for the cause. If the fuse held, no line patrol was completed, and therefore the cause code on "Unknown" would be entered. LUMA stopped this practice and instituted the requirement for a patrol of the feeder before replacing any blown fuse. This both adds time to the restoration response but greatly reduces the number of unknown outage causes. In addition, in early 2024, additional efforts were made to minimize the number of unknown outage causes. This effort succeeded in further reducing the number of unknown causes but also had the impact of slowing response time as field employees spent more effort attempting to determine the cause.

Notice that the reduction in Unknown Events drastically from FY2022 to FY2024 goes from 6,367 down to 2,912, a reduction of 3,455 events. Notice also that the increase in vegetation events from FY2022 to FY2024 goes from 9,131 to 14,561, an increase of 5,430 events. Much of this increase can be attributed to events that would have been recorded as unknown to events recorded as vegetation. But since this increase is larger than the reductions in unknown, it must be due to a combination of more aggressive patrols and actual increases in vegetation-caused outages.

With the context set with regard to the impact of unknown event reductions, the overall increase in events from FY2022 to FY2024 can be examined. This increase is from 38,444 to 46,266, an increase of 7,822 events. It is assumed that increases in actual vegetation events over this time are 5,430 – 3,455 = 1,975 events. With all the reductions in unknown being allocated to vegetation, increases in remaining categories are assumed to be actual increases.

The categories of Lightning and Weather must be considered together, as it is clear, that earlier years tended to classify a lightning-caused outage as weather. Combined Lightning/Weather events rose from FY2022 to FY2024 from 4,813 (383+4430) to 6,479 (2871+3608), an increase of 1,666 events. This corresponds to a 34.6% increase in weather events. An explanation of these increases is provided in the Weather Assessment section. Large increases are also seen in the Public category, of which LUMA has little control (these include public-cause events such as car-pole hits and dig-ins), and in the Other Category. The Other category included the following cause codes:

- Failed Protection
- Feeder Load Transferred
- Human Error
- Other Causes
- Raise / Lower Service Transfonner Tap
- Removal of Oil Container or Asbestos
- Trip Due to Overload

A breakdown of these cause codes is shown in Table 7-2. This shows that the increase in the "Other" category is almost entirely due to the "Feeder Load Transferred" cause code. This cause code is used when connected feeders are impacted by the same event, and the CMI is allocated to the feeder where the event is initiated. Therefore, these recorded events are not truly increases in actual events, but a result of how the data is handled.

Table 7-2. Breakout of "Other" Causes

"Other" Cause Category								
FY	Total	Failed Protection	Feeder Load Transferred	Human Error	Other Causes	Raise / Lower Service Tx Tap	Removal of Oil Container or Asbestos	Trip Due to Overload
2022	448	52	0	76	226	0	0	94
2023	904	38	473	72	191	0	0	129
2024	1,304	28	844	34	247	0	0	151

In any case, LUMA was faced with a large increase in the number of outage events from FY2022 to FY2024, a large percentage of which were out of LUMA's control. However, the impact on CMI increase was proportionally small. Whereas overall outage events increased by 20.3% from FY2022 to FY2024 (38,444 to 46,266), CMI decreased by 7.1% (2,300 million to 2,137 million). This can be explained by events resulting in fewer CMI on average. In FY2022, an average event resulted in 59,816 CMI. In FY2024, an average event only resulted in 46,195 CMI, a reduction of 22.8%. This has been accomplished primarily by reducing the number of customers impacted by certain outages, largely through its distribution automation (DA) initiative and its regional reliability initiative.

The DA initiative consists of the installation of single-phase reclosers and three-phase reclosers. The devices result in far fewer customers being impacted by faults that result in the new recloser operating rather than an upstream protection device. To date, LUMA has installed 593 single-phase reclosers and 284 three-phase reclosers under this program. Based on the number of operations of these devices, it is estimated that 40,971,031 CMI was avoided for FY2023, and 116,259,864 CMI was avoided in FY2024. The percentages of these avoided CMI numbers based on the entire year are shown in Table 7-3.

Table 7-3. Impact of DA Program to CMI

FY	CMI	Avoided	%
2023	1790171976	40,971,031	2.3%
2024	2137249691	116,259,864	5.4%

Although the impact of DA has been significant, additional effort has been required to counteract the effect of significantly more events from FY2022 to FY2024. This has been through regional reliability improvement programs that focus on installing more cutout fuses, faulted circuit indicators (FCIs), and optimizing fuse sized for proper coordination. To date, the programs have installed 839 new fused cutouts, 3,568 FCIs, and 4,844 fuse optimizations. It is not possible to directly calculate the impact of these devices, but it is clear that they are a major factor as to why SAIDI is not increasing significantly, even as events are increasing significantly.

In addition to the DA and regional reliability programs, LUMA has several programs focused on transmission and substations (see section on inspection and maintenance). These programs reduce the number of outages that tend to impact large numbers of customers and potentially involve large repair times. The number of outages associated with transmission, substations, and distribution are shown in Table 7-4.

Table 7-4. Outage Events By Distribution, Substations, and Transmission

Events	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024
Distribution	28,869	29,340	27,894	35,441	40,464	43,341
Substation	548	614	574	554	550	552
Transmission	3,350	3,065	3,116	2,449	2,459	2,373
Total	**32,767**	**33,019**	**31,584**	**38,444**	**43,472**	**46,266**

As can be seen, the number of substation outage events has been essentially steady, even as substation equipment continues to age. Similarly, transmission outage events have been holding steady during the LUMA Years, which showed a reduction when compared to the PREPA Years. In contrast, the number of distribution outage events is increasing, largely due to weather-related events and vegetation-related events. Both increases are associated with changing weather patterns, which are discussed in the next section.

8. Weather Severity

Since the PREB order is partially based on the increase in reported SAIDI from FY2023 to FY2024, an assessment of weather severity for these two time periods is performed. This analysis is separate from the impact of excluded MEDs due to Fiona and focuses on actual experienced weather conditions.

A review of the weather conditions between FY2023 and FY2024[1] is performed to determine the impacts of the weather conditions on the system's reliability. The weather information is from the NOAA Monthly[2] and Annual[3] Reports.

A review of monthly rainfall and temperatures was performed based on identifying the variance from the monthly averages. The key observations from this review are:

- As shown in Figure 8-1, the monthly rainfall averages are much higher in FY2024 than in FY2023. The outlier is September 2022 when Hurricane Fiona occurred.

- As shown in Figure 8-2, the monthly temperature averages are also much higher in FY2024 than in FY2023. It should also be noted that the warmest months occurred for five months during FY2024.

However, prior to identifying the reliability impacts from this comparison, it is important to look at the overall weather conditions in FY2023 and FY2024 for additional context. Based on a review of the NOAA weather data, the following observations were described:

---

1 Fiscal year (FY) 2023 goes from July 1, 2022 to June 30, 2023 and FY2024 goes from July 1, 2023 to June 30, 2024.

2 NOAA National Weather Service: "Climate and Hydrology Monthly Reports for Puerto Rico and the US Virgin."

3 NOAA National Weather Service: "Year in Review Rainfall Summaries."

- 2023 was the 3rd warmest year on record.[4]

- 2024 was the warmest year on record.[5]

- It should also be noted that coming into 2022, the Island was experiencing drought-like conditions.[6] This was followed by an increase in rainfall for FY2023, and even more increased rainfall in FY2024.

These types of weather patterns will have two primary impacts on reliability. First, increased temperatures and rainfall will cause vegetation to grow faster. Second, increased temperatures will increase system loading, causing equipment to increase in temperature due to this loading but less able to dissipate this head due to higher ambient temperatures. Therefore, the weather patterns seen in FY2023 and FY2024 will result in higher numbers of outages due to both vegetation and equipment overloading. These will now be discussed in turn.

Vegetation-related outages rose from FY2022 to FY2024 from 9,131 to 14,561. However, much of this can be attributed to the reclassification of unknown causes, which decreased from 6,367 to 2,912. Conservatively assuming that all of the reductions in unknown outage causes were transferred to vegetation, vegetation-caused outages would have increased by 1,975, still representing a 20% increase over two years. This increase can be attributed to several factors. First, as discussed previously, an increase in temperature and rainfall increases vegetation growth rate. Second, Hurricane Fiona caused large amounts of vegetation damage, which resulted in further increased vegetation growth rate. Last, the extreme temperatures cause health issues in the trees, causing them to be more prone to structurally failing and falling into power lines. These increases in growth rate and health issues are not in LUMA's control, and the only way to mitigate their effects is through more aggressive vegetation management.

---

4 NOAA National Weather Service: "2023 Year in Review."

5 NOAA National Weather Service: "2024 Year in Review."

6 NOAA National Weather Service: "2022 Climate Review for Puerto Rico and the U.S. Virgin Islands."

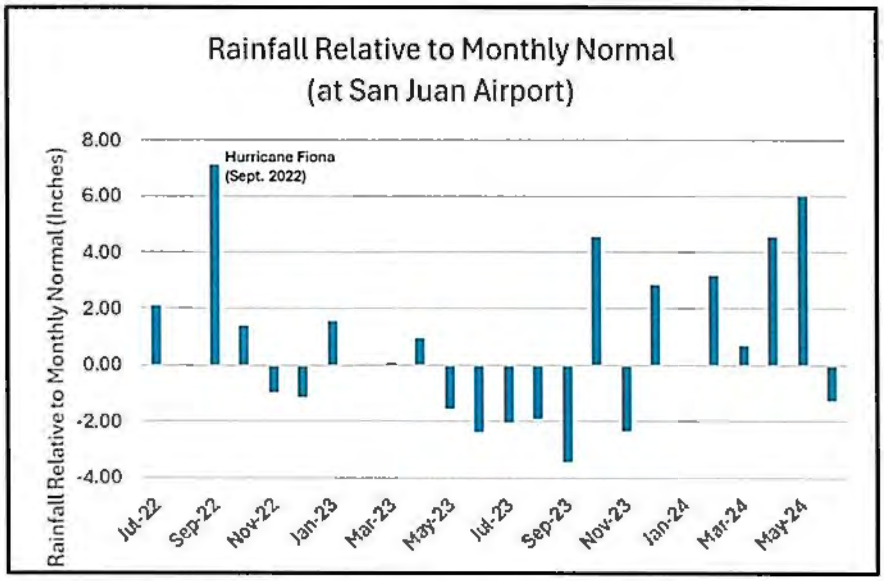


Figure 8-1. Rainfall Variance from Normal (at San Juan Airport)[7]

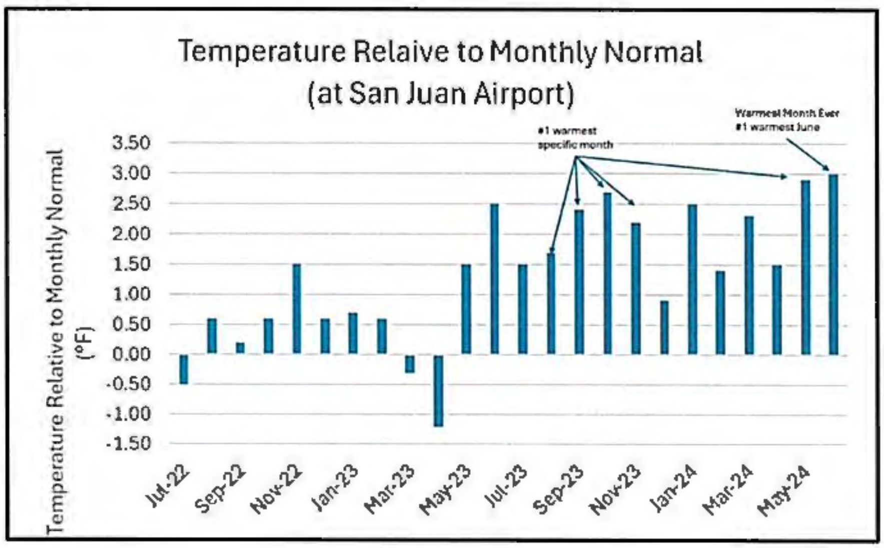


Figure 8-2. Temperature Variance from Normal (at San Juan Airport)[8]

Hotter temperatures will result in increased electricity usage. System demand for FY2022 through FY2024 is shown in Table 8-1.

---

[7] There were no specific variances provided in the monthly reports for October 2023 and November 2023 so that these values were estimated from the rainfall maps.

[8] There were no specific variances provided in the monthly reports for October 2023 and November 2023 so that these values were estimated from the various temperature and condition descriptions.

Table 8-1. Peak Demand Values (GW)

Peak Demand	FY2022	FY2023	FY2024
Minimum	2373	2258	2447
Average	2677	2608	2844
Maximum	2960	3049	3181

As can be seen, the maximum daily peak demand rose from FY2022 to FY2024 from 2,960 GW to 3,181 GW, an increase of 7.5%. Similarly, the average daily demand rose from 2,677 GW to 2,844 GW, an increase of 6.2%. These increases will result in higher currents in system equipment and corresponding higher equipment temperatures. For overhead lines, these increased temperatures will increase line sag and, therefore, the number of outages from lines sagging into vegetation. For substation equipment, these increased temperatures will accelerate equipment thermal aging and increase failure probability.

In summary, changing weather from FY2022 to FY2024 tends to make reliability worse in a manner that is not in LUMA's control. This is due to increases in vegetation growth rate, decreases in vegetation health, and increases in equipment loading.

9. Inspection and Maintenance

Equipment Reliability

A review is performed of the condition of the electric grid and actions that LUMA has taken to improve the performance of the system relative to equipment reliability.

Status of Electric System When LUMA Commenced Operations

The status of the electric grid at the time that LUMA transitioned into operation of the electric system in June 2021 was documented in the Costa Sur Outage of April 6, 2022, Root Cause Analysis Report.[9]

Key observations from that report relative to the condition of the system prior to LUMA operation are summarized below:

- Electric systems are subject to various inspection and maintenance programs to ensure that the assets and systems are safe and reliable. In 2016, maintenance and inspection activities had been greatly reduced. The electric system has been significantly impacted in the past several years by reduced preventive maintenance and by major external events (hurricanes and earthquakes). In 2016, PREPA indicated that the status of its electric system inspection and maintenance program was deteriorating.[10] This information indicated there were issues with both the maintenance program and the ability of PREPA to retain and recruit key personnel to effectively manage the inspection and maintenance program. PREPA indicated the following completion level of maintenance tasks, as shown in Figure 9-1. As indicated by the results in Figure 9-1, the effective maintenance completion had declined continuously from 2008 to 2016 to the extent that only 24% of maintenance was completed within its required time period. The

---

[9] A detailed assessment of the system condition prior to LUMA commencement of operations is provided in the following: Exponent Report: "Costa Sur Outage Event April 6, 2022 Root Cause Evaluation"; prepared for DLA Piper; dated September 16, 2022.

[10] PREPA Letter "Análisis Estadístico y Proyectado de la Conservación de Equipos Eléctricos de la Subdivisión de Conservación Eléctrica"; dated October 19, 2016.

impact of this condition is that asset condition deteriorates without the appropriate attention and leaves the system in a vulnerable state relative to equipment condition and reliability.

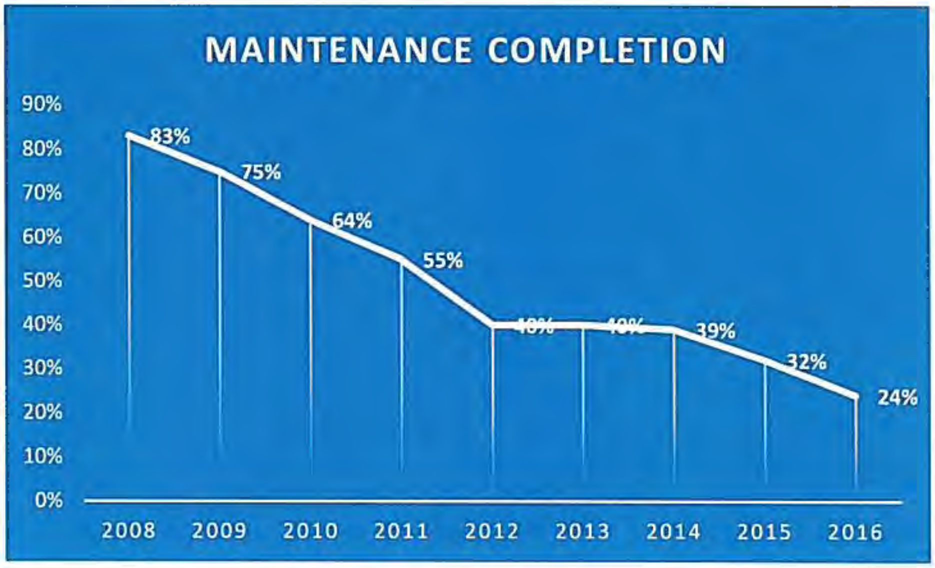


Figure 9-1. PREPA Maintenance Completion[10]

- As reported in a June 2019 independent report,[11] key observations on the reliability of the system were noted as follows:

  - "As reported from PREPA, as of March 6, 2019, 332 of 342 distribution substations had been reenergized and 54 of 56 TCs had been re-energized. As with T&D elements, even though the system has been successfully restored to serve the vast majority of PREPA customers, it is not clear what level of reliability can be expected from the substations and TCs. Many sites experienced significant flooding which can degrade critical equipment. Equipment, such as transformers and circuit breakers and the associated control panels are sensitive to moisture intrusion, especially during periods of de-energization, which can lead to lower reliability. Once the emergency restoration effort has been completed, much of the substations and TCs will need to be revisited by crews in

---

[11] "Independent Engineering Report PREPA Transmission and Distribution System" prepared by Sargent & Lundy, Report No. SL-014468.TD, dated June 2019.

order to evaluate and make the required repairs to bring them up to industry standard levels of reliability."

- "Overall, most substations and TCs were operating and in decent condition. However, overall maintenance was a concern. While newer equipment was in good condition, older equipment exhibited its age indicative of <u>inadequate maintenance practices</u>. The condition of the wiring and lack of documentation represents a significant challenge to the stations' reliable performance."

- "PREPA indicates that due to lack of labor resources, they do not generally perform scheduled or planned maintenance of the TCs, substations, or T&D systems. However, scheduled and planned maintenance is generally performed on large power transformers, oil and gas circuit breakers, station batteries, and relays on a time basis."

- "As these systems age failures will become increasingly frequent, leading to crews spending more time in restoring and performing corrective maintenance, rather than focusing on preventative maintenance that increases reliability. Older sites also pose additional challenges as drawings may be outdated or inaccurate, and years of emergency repairs can lead to non-standard installations that are more difficult to troubleshoot."

Therefore, the electric facilities were in operation but required significant maintenance and potential replacement. The major observation from the assessment of the condition in the independent report is that the electric system remains fragile from years of lack of maintenance and inspections and damage from external events.

Equipment Reliability Actions

The major activities to maintain and improve equipment reliability include:

- Asset management processes to ensure that equipment condition is known and that data management systems are in place to manage the assets: LUMA inherited a system that was mostly documented in written documents with limited database information. Since LUMA has taken over operations, they have made investments and improvements in their equipment and system databases to track assets, maintenance records and work performance. Their initial efforts focused on the 230kV system and worked down to the lower voltages on transmission and distribution. This strategy is based on the overall impact that the 230kV system has on system outages. LUMA has developed systems that track their major substation assets, such as transformers and circuit breakers, so that asset data and maintenance data are tracked, and appropriate corrective actions can be taken. Databases have been reviewed for transformers, circuit breakers, inspection information, and relays, as example.

- Inspection and maintenance process to ensure that equipment and materials are kept in good operating condition: LUMA has established a set of inspection and maintenance priorities for their substations, which are the backbone of the power grid. This strategy involves focusing on 230kV and 115kV stations to ensure their operation since they have the largest impact on the system. As stated previously, these inspections and maintenance programs are being documented within the asset database to track equipment findings and maintenance actions to completion. These are documented in individual inspection forms as well as databases tracking open actions. Additionally, LUMA has a thermography program to identify hot spots on transmission lines and substations that may require action.

- Capital projects to ensure that equipment and materials are replaced at appropriate intervals based on condition and system needs: LUMA has prepared a "Systems Improvements Preliminary Plan"[12] that defines capital programs to improve the equipment's performance and overall reliability. Since taking over operations, LUMA has been implementing multiple improvement programs in the electric system, including:

[12] LUMA "System Improvements Preliminary Plan"; dated July 19,2024.

- Near-term restoration of out-of-service equipment to stabilize the grid, including substation transformers, circuit breakers, and transmission lines.

- Long-term capital projects include substation rebuilds, new substations, transmission line pole replacements, and transmission line rebuild.

- Hardening of poorly performing assets and equipment.

This plan includes specific projects related to priority substation equipment replacement and priority transmission lines. Additionally, the project addresses upgrades and improvement through distribution automation improvements. These programs are intended to make progress in bringing the electric system back to its original design and operating state.

Based on the on-going work, LUMA has prioritized the transmission system issues for capital improvement to prevent major events, but much of the work applies to reductions in overall system reliability.

10. Vegetation Management

As increases in vegetation are a driving factor in reliability, this section addresses LUMA's actions with regard to vegetation management. LUMA is executing a vegetation management strategy that includes two distinct activities. The definition of the vegetation management work is described in the Systems Improvements Preliminary Plan (dated July 19, 2024).

The first activity is related to a one-time vegetation clearing program planned to be completed between FY2025 and FY2028. The scope of this effort covers all six regions on the Island and incorporates clearing across all substations, transmission lines, distribution lines, and telecom facilities. The work is prioritized by region and equipment type, as shown in Table 10-1 below. The first project in San Juan was started in 2024.

Table 10-1. Vegetation Clearance Prioritization

Region	Asset Type
San Juan	Distribution non-sensitive vegetation
Arecibo	Transmission 38kV non-sensitive vegetation
Bayamon	All 38kV & distribution EHP sensitive vegetation
Caguas	Transmission 115kV
Mayaguez	Substation and telecom sites
Ponce	All regions transmission 230kV

The second activity includes on-going operations of vegetation management. This activity includes vegetation management (patrols and clearing) focused on areas showing outages. The work includes the following activities:

- The 230 kV system has had reclamation work done on all lines; therefore, preventative (cyclical) maintenance will be performed from the oldest to the newest completion dates. Four circuits will be scheduled for this cycle in FY2025, and four will be scheduled in FY2026. Also, the 230 kV will be flown quarterly by the Operations transmission team to identify any potential issues related to vegetation.

- LUMA's Operations team will focus on corrective work on the 115 kV lines with 3 circuits being preventive work. For the corrective work, with the support of helicopters and ground patrols, mid-span vegetation will be identified and mitigated. The first lines in FY2025 will be the lines at risk of line sag due to load transfers during planned outages or emergency outages and any upgrade work where vegetation work will be needed.

- The 38 kV system will have approximately 200 miles cleared in FY2025 and in FY2026. These circuits being worked by operations' vegetation management have been chosen due to past reliability issues and the highest contributors to SAIDI/ SAIFI. The work performed will be corrective in nature as it will not be a full reclamation of the ROW.

- The distribution work will be performed in parallel with the 38 kV work. Approximately 600 miles will be cleared in FY2025 and LUMA anticipates the same will be completed in FY2026. This work will focus on trees that might be in close contact with a conductor.

All of the vegetation work will have a positive impact on reliability by assisting in reducing the number of vegetation-related outages. LUMA's Operations business unit will also provide support during planned outages and any upgrade work where vegetation work will be needed.

11. Summary of Reliability Performance

The PREB resolution and order asserts that LUMA's SAIDI performance in FY2024 is unacceptable because it (1) is a significant increase over FY2023 reported SAIDI; and (2) is higher than the baseline FY2020 SAIDI. An assessment of outage data from FY2019 to FY2024 shows the following:

1. SAIDI during the LUMA years (FY2022 through FY2024) has stayed essentially constant if the major event days associated with Hurricane Fiona are properly considered. After adjusting for Fiona, FY2024 shows a slight increase of 3.8% when compared to FY2023 but a slight *decrease* of 7.1% when compared to FY2022. These three years, taken together show a slightly improving SAIDI trend.
2. A comparison of reported SAIDI during the LUMA years to the baseline year of FY2020 is misleading for several reasons. First, PREPA was not recording a significant number of secondary-related outages, making reported SAIDI artificially low. Second, weather severity in FY2020 was mild when compared to all other years considered. Adjusting FY2020 for these factors so that a fair comparison with FY2024 can be made would be an increase of 1.5% to account for underreported secondary outage events and an increase of 9.5% to account for weather severity. This results in an upward adjustment of the FY2020 baseline SAIDI value of 11%, bringing it up from 1,243 minutes to 1,380 minutes. This is compared to the reported SAIDI for FY2024 of 1,432 minutes, which is a 3.8% increase.
3. However, LUMA has also implemented needed safety practices that resulted in an increased average SAIDI of 12.5%. If LUMA is not to be penalized for implementing these safety practices, reliability, not considering these safety practices, actually improved by about 8.7% (12.5% - 3.8%) when compared to the baseline year.

Based on the above assessments, it does not appear that LUMA should be fined for its FY2024 reliability performance, as it compares favorably to both the baseline year and to FY2023 when care is taken so that fair comparisons are made. Reported FY2024 SAIDI is certainly higher than reported FY2023 SAIDI and reported FY2020 SAIDI. But reported FY2023 SAIDI is not directly comparable to FY2024 due to Hurricane Fiona, and FY2020 SAIDI is not directly comparable to FY2024 due do several differences including in how PREPA and LUMA reported reliability performance. Furthermore, SAIDI during the years of LUMA operation (FY2022 – FY2024) is showing a slight trend of improvement.

And so, SAIDI has gotten slightly worse if safety practices are not accounted for and moderately better if safety practices are accounted for. This is true even as the total number of outage events has significantly increased, largely due to more severe weather and increasing vegetation-related outages. To continue managing SAIDI, a corrective action plan will, therefore have to address these trends. This will require (1) more aggressive vegetation management to address vegetation-related failures; (2) more aggressive equipment replacement and maintenance to compensate for more severe weather; and (3) a continuation of the DA program to reduce the number of customers impacted by distribution events. The proposed corrective action plan of LUMA is assessed against these aspects in the next section.

12. Corrective Action Plan

The proposed LUMA Corrective Action Plan (CAP) related to vegetation management is summarized in Table 12-1.

Table 12-1. CAP for Vegetation Management

Workstream	FY2024 Key Achievements	Timeline for Implementation	Expected Improvement
Vegetation Management and Capital Clearing Implementation	Clearing over 1,500 miles of distribution and transmission lines; completing the fifth round of substation herbicide treatment; completing 70 percent of substations treated on the sixth round; and starting the federally funded vegetation clearing initiative with San Juan Group A obligations.	Vegetation-clearing efforts are planned to occur over the next four years (between FY2025 and FY2028). After the Vegetation Reset program, LUMA will establish and maintain a four-year cycle for power line maintenance.	Vegetation Management and Capital Clearing workstreams estimates at the end of fiscal year 2028 indicate an overall reduction of 400 million in CMI.

The plan is for LUMA to perform a capital vegetation clearing "reset" and then establish a 4-year trim cycle for vegetation. When this happens, it will address a large component of LUMA's reliability challenge, which is an increasing number of vegetation-related outages. For a historical perspective, here are the vegetation management budget numbers for the LUMA years:

- FY2022 - Approved budget $49.4M / Actual $50.9M
- FY2023 - Approved budget $52.5M / Actual $62.7M
- FY2024 - Approved budget $56 / Actual $55.7M

These budgets corresponded to the following number of cleared circuit miles:

- FY22 – 916.47 miles
- FY23 – 1839.65 miles
- FY24 – 1451.44 miles

The system consists of more than 16,000 miles of right-of-way that requires vegetation management (there are more circuit-miles that this since there are often multiple circuits in the same right-of way). Therefore, moving to a 4-year trim cycle from the current "trim when a problem occurs" will represent a large change. This CAP for vegetation management is appropriate but should be closely tracked to ensure it becomes fully implemented.

The proposed CAP related to aging equipment is summarized in Table 12-2. At this point, LUMA is doing a good job of managing equipment failures due to aging equipment, as outage events due to equipment are essentially holding steady. Table 12-2 represents a continuation of LUMA's current equipment replacement plan and is appropriate based on an assessment of reliability drivers – continuing its plan should prevent equipment failures due to aging equipment from increasing.

Table 12-2. CAP for Aging Equipment

Workstream	FY2024 Key Achievements	Timeline for Implementation	Expected Improvement
Distribution Line Rebuild	Submitting one initial Scope of Work (SOW) for distribution underground work; submitting 18 detailed SOWs representing 98 feeders; dividing feeder project groups into individual 151 priority feeder projects to speed up the obligation process; and completing 35 area plans of 71 areas outlined.	Workstream goal is to replace over 200 miles of distribution lines from FY2026 to FY2029.	Workstream initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 100 million in CMI and a minimum of 600 million CMI avoided by the end of the program.
Distribution Pole and Conductor Repair	Installation of more than 4,300 poles and submitting six initial SOWs and 12 detailed SOWs to obtain FEMA funding obligation for 3,872 poles. We received funds obligation for two projects totalizing 301 poles.	Workstream goal is to replace up to 24,000 Critical Poles by FY2036.	Workstream initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 180 million in CMI and a minimum of 320 million CMI avoided by the end of the program.
Transmission Line Rebuild	Replacing six transmission structures on one of the worst-performing transmission lines; submitting 20 initial SOWs to address system reliability improvements to the PREB; submitting four detailed SOWs to FEMA; evaluating proposed projects to assess the scopes with the highest impact and dividing those transmission line rebuilds into multiple projects bounded by adjacent substations to drive efficiency and project execution.	Transmission Line Rebuilds efforts are planned to start in FY2027. A total of 15 transmission lines are to be impacted by the end of FY2028. By the end of FY2035, LUMA expects to finalize a total of 49 Transmission Line Segments.	Transmission Line Rebuild and Transmission Line Pole replacement workstreams initiatives estimates at the end of fiscal year 2028 indicate an overall reduction of 18 million in CMI and a minimum of 130 million CMI avoided by the end of the program.
Transmission Priority Pole Replacement	Replacing 27 structures, installing seven pole bases, making 164 critical repairs, designing 108 structures, and submitting ten initial SOWs and nine detailed SOWs to FEMA for an obligation of funds for 53 structure replacements and 52 critical repairs.	Transmission Line Pole Replacement efforts are planned to start in FY2026. LUMA plans to impact over 200 transmission line structures by the end of FY2028.	Transmission Line Rebuild and Transmission Line Pole replacement workstreams initiatives estimates at the end of fiscal year 2028 indicate an overall reduction of 18 million in CMI and a minimum of 130 million CMI avoided by the end of the program.
Substation Rebuild	Installation and energizing breakers in Aguirre, Añasco, Daguao, Sabana Llana, Palmer and Venezuela substations. We also installed transformers in Sabana Llana, Monacillos Aguada, and Venezuela. Submitted eleven detailed SOWs to FEMA for substation rebuild and minor repair project group as well as for the Acacias substation relocation.	Substation Rebuilds efforts are planned to start in FY2026. A total of 38 substations are to be impacted by the end of FY2028.	Substation Rebuild workstream initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 67 million in CMI and a minimum of 250 million CMI avoided by the end of the program.

The proposed LUMA CAP related to outage impact is shown in Table 12-3. The impact of outages can be mitigated by having fewer customers affected and by having these customers restored more quickly. The LUMA DA program largely addresses the first mechanism.

Table 12-3. CAP for Outage Impact

Workstream	FY2024 Key Achievements	Timeline for Implementation	Expected Improvement
Distribution Automation	Installation of 1,381 circuit fault indicators, 212 three-phase reclosers, 407 single-phase reclosers, and 458 cutouts. Additionally, we conducted 3,393 fuse optimizations. We completed protection settings for 190 feeders, performed reliability analysis for more than 500 feeders, completed work order packages for 2,881 devices, and submitted 13 detailed SOWs.	LUMA plans to continue installing more than 11,000 automation devices in the next two years (FY2025-FY2026), including three-phase reclosers, single-phase reclosers, communicating fault current indicators, and distribution protective devices.	Distribution Automation initiative estimates at the end of the fiscal year 2028 indicate an overall reduction of 230 million in CMI and a minimum of 430 million CMI avoided by the end of the program.

The DA program has been very successful at keeping SAIDI fairly constant while outage events have increased significantly. It is, therefore, appropriate to continue this program.

In summary, the proposed LUMA CAP is appropriate for effectively managing SAIDI and, if fully implemented, should result in a downward SAIDI trend. These benefits are especially dependent upon the successful implementation of a cycle-based vegetation management program for both transmission and distribution, as increasing vegetation-related outages have been significantly increasing in recent years.

Exponent®
Engineering & Scientific Consulting

Richard E. Brown, Ph.D., P.E.

Principal Engineer | Electrical Engineering & Computer Science
1331 17th Street, Suite 515 | Denver, CO 80202
(303) 882-6469 tel | rbrown@exponent.com

Professional Profile

Dr. Brown is an internationally recognized expert in infrastructure asset management, power system reliability, major event performance, system hardening, reliability improvement, power delivery system planning, smart grid, system automation, distributed energy resources, risk assessment, and economic analysis. He has submitted expert witness testimony to regulatory commissions in the states of California, Florida, Maryland, Massachusetts, Virginia, Ohio, and Texas. He has developed several generations of distribution system reliability assessment software tools, and has helped a large number of utilities to develop cost-justified reliability improvement plans. Dr. Brown is an experienced testifying expert in both regulatory proceedings and in civil cases

Dr. Brown has extensive experience with extreme weather events including hurricanes, linear winds, tornadoes, fires, earthquakes, floods, ice storms, and winter storms. This includes post-event analyses to examine utility infrastructure performance, restoration performance, and storm cost recovery support. Dr. Brown is also one of the early pioneers in transmission and distribution system hardening against major weather events, and has helped several major utilities develop and implement infrastructure hardening programs. He led a consortium of Florida utilities under the direction of the Florida Public Utilities Commission do develop a probabilistic storm and restoration simulation to quantify the costs and benefits of hardening options. Dr. Brown was also retained by the Public Utilities Commission of Texas to quantify the costs and benefits of proposed system hardening legislation, and to recommend best practices.

Dr. Brown has extensive experience in electric system outage investigations including major urban interruption events in cities including Chicago, San Francisco, New York City, Calgary, B.C., Vancouver B.C., and Denver. He has also provided expert witness testimony for utilities facing civil actions after accidents involving electric utility system infrastructure.

Prior to Exponent, Dr. Brown held executive positions at ABB, KEMA, Quanta Technology, and WorleyParsons. He has published more than 90 technical papers, has taught courses in eleven countries, and is author of the books *Electric Power Distribution Reliability* and *Business Essentials for Utility Engineers*. Dr. Brown is a Fellow of the IEEE and a registered professional engineer.

Academic Credentials & Professional Honors

Ph.D., Electrical Engineering, University of Washington, 1996

M.S., Electrical Engineering, University of Washington, 1993

B.S., Electrical Engineering, University of Washington, 1991

M.B.A., Business Administration, University of North Carolina, Chapel Hill, 2003

IEEE Fellow

Eta Kappa Nu

Beta Gamma Sigma

Licenses and Certifications

Licensed Professional Engineer, North Carolina, #23088

Academic Appointments

Adjunct Faculty Member, North Carolina State University, 2008-2013

Prior Experience

Vice President, U.S. Power Networks, WorleyParsons, 2012-2013

Vice President, Operations, Quanta Technology, 2006-2012

Vice President, Asset Management, KEMA, 2003-2006

Director of Technology, ABB Consulting, 2001-2003

Principal Engineer, ABB Power Distribution Solutions, 1999-2001

Senior Engineer, ABB Corporate Research, 1996-1999

Research/Teaching Assistant, University of Washington, 1994-1996

Electrical Engineer II-III, Jacobs Engineering, 1991-1993

Professional Affiliations

IEEE Power Engineering Society Activities

- Elected IEEE Fellow in 2007 for contributions to distribution system reliability and risk assessment. The grade of Fellow is conferred by the IEEE Board of Directors for an extraordinary record of industry accomplishments, and is limited to one-tenth of one percent of the total voting membership per year.
- Member of IEEE Herman Halperin Awards Committee (2011 - present). This is an IEEE society-level position.
- Chair, Technical Awards Committee (2007 - 2013)
- Member, Power System Planning and Implementation Committee (1997-present)
  - Committee Vice Chair (2006-2008)
  - Chair, Distribution Working Group (2003-2006)
  - Chair, Power Delivery Reliability Working Group (1997-1999)
- Member, Distribution Subcommittee, Reliability Working Group (1997-present)
- Technical Paper Reviewer IEEE Transactions on Power Systems (1996-present)
  - IEEE Transactions on Power Delivery (1996-present)

  - IEEE General Meeting (2001-present)
  - IEEE T&D Conference and Exposition (2001-present)
  - IEEE Power Systems Conference and Exposition (2004-present)
  - IEEE Power Systems Computation Conference, 2008
- President, University of Washington Student Chapter (1994-1995)
- Vice President, University of Washington Student Chapter (1993-1994)

Publications

Books, Book Chapters, and Theses

Brown RE. Business Essentials for Utility Engineers. CRC Press, 2010.

Brown RE. Electric Power Distribution Reliability, Second Edition. CRC Press, 2009.

Brown RE. Electric Power Distribution Reliability. Marcel Dekker, 2002.

Morrow DJ, Brown RE. Future vision: The challenge of effective transmission planning. Chapter 6, Power System Analysis and Design, 5th Edition, J. D Glover et al. (Editor), pp. 295-304.

Brown RE, Willis HL. Substation asset management. Chapter 19, Electric Power Substations Engineering, J. D. McDonald (Editor), Taylor & Francis (CRC Press), 2007, pp. 19-1 through 19-31.

Brown RE. Power System Reliability Section 13.5, Electric Power Engineering Handbook, L. L. Grigsby (Editor), CRC Press LLC, 2001, pp. 13-51 through 13-65.

Brown RE. Predictive Distribution Reliability and Risk Assessment. Chapter 3, IEEE Tutorial on Probabilistic T&D System Reliability Planning, A. A. Chowdhury (Editor), IEEE 07TP182, 2007, pp. 29-36.

Brown RE. Distribution System Reliability: Analytical and Empirical Techniques. Chapter 3, IEEE Tutorial on Electric Delivery System Reliability Evaluation, J. Mitra (Editor), IEEE 05TP175, 2005, pp. 39-51.

Brown RE. Reliability Assessment and Design Optimization for Electric Power Distribution Systems, Ph.D. Dissertation, University of Washington, Seattle, WA, 1996.

Brown RE. An Intelligent Overload Relay for Extruded Dielectric Transmission Cable, Master's Thesis, University of Washington, Seattle, WA, 1993.

Refereed Journal Papers

Brown RE, Wilson CS, van Nispen H. Becoming the utility of the future. IEEE Power and Energy Magazine Sept/Oct 2016; 14(5):57-65.

Brown RE, Morrow DJ. Future vision. IEEE Power and Energy Magazine 2007 Sept/Oct; 5(5):36-45.

Brown RE, Willis HL. The economics of aging infrastructure. IEEE Power and Energy Magazine 2006 May/June; 4(3):36-43.

Brown RE. Engel MV, Spare JH. Making sense of worst performing feeders. IEEE Transactions on Power Systems 2005 May; 20(2):1173-1178.

Brown RE, Humphrey BG. Asset management for transmission and distribution. IEEE Power and Energy

Magazine 2005 May/June; 3(3):39-45.

Brown RE, Frimpong G, Willis HL. Failure rate modeling using equipment inspection data. IEEE Transactions on Power Systems 2004 May; 19(2):782-787.

Venkata SS, Pahwa A, Brown RE, Christie RD. What future distribution engineers need to learn. IEEE Transactions on Power Systems 2004 Feb; 19(1):17-23.

Li F, Brown RE. A cost-effective approach of prioritizing distribution maintenance based on system reliability. IEEE Transactions on Power Delivery 2004 Jan; 19(1):439-441.

Li F, Brown RE, Freeman LAA. A linear contribution factor model of distribution reliability indices and its applications in Monte Carlo simulation and sensitivity analysis. IEEE Transactions on Power Systems 2003 Aug; 18(3):1213-1215.

Li F, Freeman LAA, Brown RE. Web-enabling applications for outsourced computing. IEEE Power and Energy Magazine 2003 Jan/Feb; 1(1):53-57.

Brown RE, Hanson AP. Impact of two stage service restoration on distribution reliability. IEEE Transactions on Power Systems 2001 Nov; 16(4): 624-629.

Brown RE, Hanson AP, Willis HL, Luedtke FA, Born MF. Assessing the reliability of distribution systems. IEEE Computer Applications in Power 2001 Jan; 14(1): 44-49.

Brown RE, Burke JJ. Managing the risk of performance based rates. IEEE Transactions on Power Systems 2000 May; 15(2):893-898.

Brown RE, Marshall MM. Budget constrained planning to optimize power system reliability. IEEE Transactions on Power Systems 2000 May; 15(2):887-892.

Brown RE. The Impact of heuristic initialization on distribution system reliability optimization. International Journal of Engineering Intelligent Systems for Electrical Engineering and Communications 2000 March; 8(1):45-52.

Brown RE, Ochoa JR. Impact of sub-cycle transfer switches on distribution system reliability. IEEE Transactions on Power Systems 2000 Feb; 15(1):442-447.

Brown RE, Taylor TM. Modeling the impact of substations on distribution reliability. IEEE Transactions on Power Systems 1999 Feb; 14(1):349-354.

Brown RE, Ochoa JR. Distribution system reliability: Default data and model validation. IEEE Transactions on Power Systems 1998 May; 13(2):704-709.

Brown RE, Christie RD, Venkata SS, Fletcher RD. Distribution system reliability: Momentary interruptions and storms. IEEE Transactions on Power Delivery 1997 Oct; 12(4):1569-1575.

Brown RE, Gupta S, Christie RD, Venkata SS, Fletcher RD. Automated primary distribution system design: Reliability and cost optimization. IEEE Transactions on Power Delivery 1997 April; 12(2):1017-1022.

Brown RE, Gupta S, Christie RD, Venkata SS, Fletcher RD. Distribution system reliability analysis using hierarchical Markov modeling. IEEE Transactions on Power Delivery 1996 Oct; 11(4):1929-1934.

Chuvychin VN, Gurov NS, Venkata SS, Brown RE. An adaptive approach to load shedding and spinning reserve control during underfrequency conditions. IEEE Transactions on Power Systems 1996 Nov;

11(4):1805-1810.

Refereed Conference Papers

Brown RE, Hwang B, Touzel R. Demand response as a dispatchable resource. POWER-GEN International, Orlando, FL, November 2013.

Romero Agüero J, Brown RE. Distribution system reliability improvement using predictive models. IEEE PES 2009 General Meeting, Calgary, Alberta, July 2009.

Romero Agüero J, Brown RE, Spare JH, Phillips E, Xu L, Wang J. A reliability improvement roadmap based on a predictive model and extrapolation technique. IEEE PES 2009 Power Systems Conference and Exposition, Seattle, WA, March 2009.

Romero Agüero J, Brown RE, Spare JH, Phillips E, Xu L, Wang J. A reliability improvement roadmap based on a predictive model and extrapolation technique. DistribuTECH Conference and Exhibition, San Diego, CA, February 2008.

Brown RE. Asset management standards and guidelines. EPRI Fourth Power Delivery Asset Management Conference, Chicago, IL, October 2008.

Brown RE. Impact of smart grid on distribution system design. IEEE PES 2008 General Meeting, Pittsburg, PA, July 2008.

Xu L, Brown RE. A hurricane simulation method for Florida utility damage and risk assessment. IEEE PES 2008 General Meeting, Pittsburg, PA, July 2008.

Brown RE. Hurricane hardening efforts in Florida. IEEE PES 2008 General Meeting, Pittsburg, PA, July 2008.

Xu L, Brown RE. Simulation of hurricane damage to utilities in Florida. DistribuTECH Conference and Exhibition, Tampa Bay, FL, January 2008.

Brown RE. Reliability benefits of distributed generation on heavily loaded feeders. IEEE PES 2007 General Meeting, Tampa, FL, June 2007.

Brown RE. Pole hardening following Hurricane Wilma. 2007 Southeastern Utility Pole Conference, Tunica, MS, February 2007.

Ramanathan B, Hennessy D, Brown RE. Decision-making and policy implications of performance-based regulation. IEEE Power Systems Conference and Exhibition, Atlanta, GA, October 2006.

Brown RE. The regulatory usefulness of reliability reporting. 2006 IEEE Rural Electric Power Conference, Albuquerque, NM, April 2006.

Butts M, Spare JH, Brown RE. Practical and verifiable reliability improvement at the Baltimore Gas and Electric Company. DistribuTECH Conference and Exhibition, Tampa Bay, FL, February 2006.

Brown RE. Project selection with multiple performance objectives. 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, September 2005.

Brown RE, Spare JH. The effects of system design on reliability and risk. 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, September 2005.

Brown RE, Spare JH. A survey of U.S. Reliability Reporting Processes. 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, September 2005.

Zhou Y, Brown RE. A practical method for cable failure rate modeling. 2005 IEEE/PES Transmission and Distribution Conference and Exposition, New Orleans, LA, September 2005.

Brown RE, Spare JH. Asset management and financial risk. DistribuTECH Conference and Exhibition, San Diego, CA, January 2005.

Brown RE, Spare JH. Asset management, risk, and distribution system planning. IEEE Power Systems Conference and Exhibition, New York, NY, October 2004.

Brown RE. Identifying worst performing feeders. Probabilistic Methods Applied to Power Systems, PMAPS 2004, Ames, IA, September 2004.

Willis HL, Engel MV, Brown RE. Equipment demographics - Failure analysis of aging T&D infrastructures. 2004 Canada Power Conference, Toronto, Canada, September 2004.

Brown RE. Failure rate modeling using equipment inspection data. IEEE PES 2004 General Meeting, Denver, CO, June 2004.

Brown RE. Coming to grips with distribution asset management. 2003 Real World Conference: It's All About Cost and Reliability, Transmission and Distribution World, Ft. Lauderdale, FL, October 2003.

Brown RE. Reliability standards and customer satisfaction. 2003 IEEE/PES Transmission and Distribution Conference and Exposition, Dallas, TX, September 2003.

Pahwa A, Gupta S, Zhou Y, Brown RE, Das S. Data selection to train a fuzzy model for overhead distribution feeders failure rates. International Conference on Intelligent Systems Applications to Power Systems, Lemnos, Greece, September 2003.

Brown RE. Network reconfiguration for improving reliability in distribution systems. IEEE PES 2003 General Meeting, Toronto, Canada, July 2003.

Brown RE, Pan J, Liao Y, Feng X. An application of genetic algorithms to integrated system expansion optimization. IEEE PES 2003 General Meeting, Toronto, Canada, July 2003.

Brown RE, Freeman LAA. A Cost/benefit comparison of reliability improvement strategies. DistribuTECH Conference and Exhibition, Las Vegas, NV, February 2003.

Gupta S, Pahwa A, Brown RE, Das S. A fuzzy model for overhead distribution feeders failure rates. NAPS 2002: 34th Annual North American Power Symposium, Tempe, AZ, October 2002.

Brown RE. Web-based distribution system planning. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Brown RE. System reliability and power quality: Performance-based rates and guarantees. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Brown RE. Modeling the reliability impact of distributed generation. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Gupta S, Pahwa A, Brown RE. Data needs for reliability assessment of distribution systems. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Brown RE. Meeting reliability targets for least cost. DistribuTECH Conference and Exhibition, Miami, FL, February 2002.

Gupta S, Pahwa A, Brown RE. Predicting the failure rates of overhead distribution lines using an adaptive-fuzzy technique. NAPS 2001: 33rd Annual North American Power Symposium, College Station, TX, October 2001.

Jones PR, Brown RE. Advanced modeling techniques to identify and minimize the risk of aging assets on network performance. Utilities Asset Management 2001, London, UK, July 2001.

Brown RE. Distribution reliability modeling at Commonwealth Edison. 2001 IEEE/PES Transmission and Distribution Conference and Exposition, Atlanta, GA, October 2001.

Brown RE. Distribution reliability assessment and reconfiguration optimization. 2001 IEEE/PES Transmission and Distribution Conference and Exposition, Atlanta, GA, October 2001.

Brown RE, Pan J, Feng X, Koutlev K. Siting distributed generation to defer T&D expansion. 2001 IEEE/PES Transmission and Distribution Conference and Exposition, Atlanta, GA, October 2001.

Ross D, Freeman L, Brown RE. Overcoming data problems in predictive distribution reliability modeling. 2001 IEEE/PES Transmission and Distribution Conference and Exposition, Atlanta, GA, October 2001.

Brown RE, Freeman LAA. Analyzing the reliability impact of distributed generation. IEEE PES Summer Power Meeting, Vancouver, BC, Canada, July 2001.

Brown RE, Marshall M. Microeconomic examination of distribution reliability targets. IEEE PES Winter Power Meeting, Columbus, OH, January 2001, Vol. 1, pp. 58-65.

Jones PR, Brown RE. Investment Planning of networks using advanced modeling techniques. Utilities Asset Management 2001, London, UK, January 2001.

Brown RE. Probabilistic reliability and risk assessment of electric power distribution systems. DistribuTECH Conference and Exhibition, San Diego, CA, February 2001.

LaPlace C, Hart D, Brown RE, Mangum W, Tellarini M, Saleeby JE. Intelligent feeder monitoring to minimize outages. Power Quality 2000 Conference, Boston, MA, October 2000.

Brown RE, Nguyen H, Burke JJ. A systematic and cost effecting method to improve distribution reliability. IEEE PES Summer Meeting, Edmonton, AB, Vol. 2, pp. 1037-1042, July 1999.

Brown RE, Taylor TM. Modeling the impact of substations on distribution reliability. IEEE PES Winter Meeting, New York, NY, pp. 349-354, February 1999.

Brown RE, Hanson AP, Marshall MM, Willis HL, Newton B. Reliability and capacity: A spatial load forecasting method for a performance based regulatory environment. 1999 Power Industry Computer Applications Conference, Dayton, OH, pp. 139-144, February 1999.

Brown RE, Hanson AP, Hagan D. Long range spatial load forecasting using non-uniform areas. 1998 IEEE/PES Transmission and Distribution Conference, New Orleans, LA, Vol. 1, pp. 369-373, April 1999.

Brown RE. Zimmermann WS, Bambao Jr PP, Simpao LP. Basic planning for a new fast growing area in Manila with a total electrical load of 650 MVA. 12th Annual Conference of the Electric Power Supply Industry, Pattaya, Tailand, November 1998.

Chao XY, Brown RE, Slump D, Strong C. Reliability benefits of distributed resources. Power Delivery International '97 Conference, Dallas, TX, December 1997.

Brown RE. Competitive distribution systems: A reliability perspective. American Power Conference, Vol. 59-II, Chicago, IL, pp. 1115-1120, April 1997.

Brown RE, Venkata SS, Christie RD. Hybrid reliability optimization methods for electric power distribution systems. International Conference on Intelligent Systems Applications to Power Systems, Seoul, Korea, IEEE, July 1997.

Brown RE, Gupta S, Christie RD, Venkata SS, Fletcher RD. Automated primary distribution system design: Reliability and cost optimization. 1996 IEEE/PES Transmission and Distribution Conference, Los Angeles, CA, September, 1996, pp. 1-6.

Brown RE, Gupta S, Christie RD, Venkata SS. A genetic algorithm for reliable distribution system design. International Conference on Intelligent Systems Applications to Power Systems, Orlando, FL, pp. 29-33, January 1996.

Technical Articles

Brown RE. Counterintuitive strategies. Transmission and Distribution World, March 2013.

Brown RE. Storm hardening distribution systems. Transmission and Distribution World, June 2010.

Brown RE. A beautiful grid? Transmission and Distribution World, February 2010.

Brown RE. Business realities. Transmission and Distribution World, January 2009.

Willis HL, Brown RE. What happens with a lack of long range T&D infrastructure planning? Natural Gas & Electricity 2008 Jan; 24(6):22-27.

Brown RE. Increased performance expectations for major storms. Electric Perspectives, EEI, June 2007.

Engel MV, Brown RE, Phillips E, Bingel N. Extreme winds test wood pole strength. Transmission and Distribution World, May 2007; pp. 34-38.

Brown RE. Asset management: balancing performance, cost, and risk. EnergyPulse Special Issue on Asset Management, www.energycentral.com, February 2005.

Musser P, Brown RE, Eyford T, Warren C. Too many routes of reliability. Transmission and Distribution World, June 2004; pp. 17-22.

Taylor TM, Brown RE, Chan ML, Fletcher RH, Larson S, McDermott T, Pahwa A. Planning for effective distribution. IEEE Power and Energy Magazine 2003; 1(5):54-62.

Brown RE, Freeman LAA. A cost/benefit comparison of reliability improvement strategies. Electric Power and Light, May 2003.

Brown RE, Kazemzadeh H, Williams BR, Mansfield CB. Engineering Tools Move into Cyberspace. Transmission and Distribution World, March 2003; pp. 27-36.

Perani P, Brown RE. Maintaining reliable power for semiconductor manufacture. What's New in Electronics, March 2002.

Perani P, Brown RE. Rock steady: The importance of reliable power distribution in microprocessor manufacturing plants. ABB Review, 2002; 3:29-33.

Willis HL, Brown RE. Is DG ready for the last mile? Power Quality (cover story), March 2002; pp. 16-21.

Brown RE, Marshall MW. The cost of reliability. Transmission and Distribution World (cover story), Dec. 2001; pp. 13-20.

Brown RE, Jones PR, Trotter S. Planning for reliability. Trans-Power Europe 2001 March; 1(1):10-12.

Brown RE, Howe B. Optimal deployment of reliability investments. E-Source, Power Quality Series: PQ-6, March 2000.

Invited Presentations

Panel Member. Demand response as a dispatchable resource. POWER-GEN International, Orlando, FL, November 2013.

Panel Member. Changing infrastructure requirements for major weather events. IEEE PES 2012 General Meeting, San Diego, CA, July 2012.

Speaker. Cost recovery of storm response expenses including mutual aid. EEI Transmission, Distribution, and Metering Conference, Louisville, KY, April, 2011.

Keynote Speaker. Cost effective reliability improvement. Exactor Smart Grid and Overhead Distribution Reliability Conference, Columbus, OH, February 2010.

Speaker. Reliability analysis in a budget constrained world. Georgia EMC Engineer's Conference, Pine Mountain, GA, October 2009.

Speaker. Impact of climate change on power system design. Midwest Energy Association (MEA) Electric Operations Conference, Springfield, Il, May 2009.

Speaker. Storm hardening: What can we do to avoid damage? Emergency Preparedness and Service Restoration for Utilities, Infocast Conference, Houston, TX, March 2009.

Speaker. Costs and benefits of overhead to underground conversion. Webinar on Utility Undergrounding, Chartwell, Aug. 2008.

Speaker. Quantifying the impacts of reliability improvements. EPRI Power Quality Applications (PQA) and Advanced Distribution Automation (ADA) 2008 Joint Conference and Exhibition, Cleveland, OH, Aug. 2008.

Speaker. Towards a greener feeder. The Carbon Challenge: Management Strategies & Practical Approaches, NRECA Cooperative Research Network, Nashville, TN, July 2008.

Session Chair. T&D reliability. IEEE PES 2008 General Meeting, Pittsburg, PA, July 2008.

Speaker. Infrastructure asset management. Marcus Evans T&D Asset Management Conference, Denver, CO, July 2008.

Speaker. Cost effective reliability improvement. 2008 Milsoft User's Group Meeting, Orlando, FL, June 2008.

Speaker. An entrepreneurial adventure. New Ventures, University of North Carolina at Chapel Hill, May 2008.

Speaker. Undergrounding electric distribution cost effectiveness, reliability, & aesthetics. Florida

Municipal Electricity Association (FMEA) Energy Connections Conference, Jacksonville, FL, October 2007.

Session Chair. T&D reliability. IEEE PES 2007 General Meeting, Tampa, FL, June 2007.

Session Chair. Transmission market issues. IEEE PES 2007 General Meeting, Tampa, FL, June 2007.

Workshop Leader. Distribution asset management and aging infrastructure. Canadian Electrical Association Workshop on Aging Distribution Infrastructure, Kelowna, Canada, May 2007.

Speaker. Hardening distribution systems for extreme wind. Chartwell Distribution Reliability Summit, Atlanta, Georgia, March 2007.

Speaker. Pole hardening following Hurricane Wilma. 2007 Southeastern Utility Pole Conference, Tunica, MS, February 2007.

Speaker. Hurricane hardening. IEEE International Conference on Transmission & Distribution Construction, Operation & Live-Line Maintenance (ESMO), Albuquerque, NM, October 2006.

Speaker. Hurricane Wilma and FPL. 2006 IEEE PES General Meeting, Montreal, Canada, June 2006.

Speaker. Hurricane hardening. 2006 EEI Transmission, Distribution & Metering Spring Conference, Houston, Texas, April 2006.

Speaker. Evaluating infrastructure integrity. Rebuilding Utility Infrastructure Conference, Louisiana State University, February, 2006.

Speaker. Improving island reliability with better asset management. 2005 CARELEC Engineers Conference and Supply Chain Seminar, Puerto Rico, July 2005.

Session Chair. Project evaluation and selection. 2005 IEEE/PES Transmission and Distribution Conference, New Orleans, LA, October 2005.

Session Chair. Distribution planning and implementation issues for modern power systems. IEEE PES General Meeting, San Francisco, CA, June 2005.

Speaker. Planning for aging infrastructure. IEEE PES General Meeting, San Francisco, CA, June 2005.

Panel Member. Assessing the impact on reliability indices after adding an OMS. 2004 IEEE/PES Transmission and Distribution Conference, New Orleans, LA, October 2005.

Panel Member. Effects of system design on reliability. 2004 IEEE/PES Transmission and Distribution Conference, New Orleans, LA, October 2005.

Instructor. Asset management for transmission and distribution. 1-Day Course, DistribuTECH Conference and Exhibition, San Diego, CA, January 2005.

Session Chair. Planning non-traditional distribution systems. IEEE Power Systems Conference and Exposition, New York, NY, October 2004.

Speaker. Asset management and financial risk. Conference on Probabilistic Methods Applied to Power Systems, Ames, Iowa, September 2004.

Session Chair. Equipment failure rates. IEEE PES General Meeting, Denver, CO, June 2004.

Instructor. Distribution reliability. 1-Day Course, T&D World Expo, Indianapolis, IN, May 2004.

Instructor. Distribution asset management for transmission and distribution. 1-Day Course, PMI Management Development for Indian Utility Executives, Madrid, Spain, April 2004.

Speaker. Distribution asset management. 2003 Real World Conference: It's All About Cost and Reliability, Transmission and Distribution World, Ft. Lauderdale, FL, October 2003.

Speaker. The 2004 Northeast Blackout. NC State IEEE/PES Student Chapter, October 2003.

Panel Member. Distribution reliability standards and their basis. 2003 IEEE/PES Transmission and Distribution Conference, Dallas, TX, September 2003.

Session Chair. Power system planning in an evolving regulatory environment. IEEE PES Summer Power Meeting, Toronto, Ontario, July 2003.

Panel Member. Distribution system reconfiguration. IEEE PES Summer Power Meeting, Toronto, Ontario, July 2003.

Panel Member. IT solutions for distribution system planning. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Panel Member. Distribution system reliability assessment. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Panel Member. Current status of DG models for feeder analysis. IEEE PES Summer Power Meeting, Chicago, IL, July 2002.

Speaker. Tools for cost-effectively improving reliability. Managing Distribution Systems in a Deregulated Environment, EUCI, Denver, CO, May 2002.

Session Chair. Impact of DG on system reliability. Power Systems 2002 Conference: Impact of Distributed Generation, Clemson, SC, March 2002.

Speaker. How to apply reliability improvement methods to your distribution system. Electric Distribution Reliability Planning Conference, INFOCAST, Seattle, WA, Nov. 2001.

Panel Member. Status of distribution reliability in the United States. 2001 IEEE/PES Transmission and Distribution Conference, Atlanta, GA, October 2001.

Panel Member. Distribution system reliability and reconfiguration software tools. 2001 IEEE/PES Transmission and Distribution Conference, Atlanta, GA, October 2001.

Panel Member. Challenges in distribution system analysis. IEEE PES Summer Power Meeting, Vancouver, BC, Canada, July 2001.

Panel Member. What are the appropriate reliability targets for distribution companies to meet? IEEE PES Winter Power Meeting, Columbus, OH, January 2001.

Speaker. Distribution reliability challenges. Distribution System Planning, Maintenance and Reliability Conference, EUCI, Denver, CO., Nov. 2000.

Speaker. Reliability-based planning methods: How to choose a method that best meets your reliability goals. Electric Distribution Reliability Planning Conference, INFOCAST, Chicago, IL, September 2000.

Speaker. The impact of deregulation on electric power system reliability. CUEPRA Summer Meeting, Charlotte, NC, July 2000.

Speaker. Tools for analyzing and valuing distribution reliability. Power Delivery Reliability Conference, INFOCAST, Denver, CO, June 2000.

Panel Member. Rates and reliability — Peaceful co-existence. DistribuTECH Conference, Miami, FL, February 2000.

Speaker. Optimizing distribution reliability at minimum cost using computer optimization. Improving Distribution Reliability Conference, Washington D.C., January 2000.

Speaker. Managing cost, reliability, and financial risk for power distribution systems. E-Source Power Quality Summit, Chicago, IL, Nov. 1999.

Speaker. Noteworthy topics in power system planning in a deregulated environment. IEEE PES Winter Power Meeting, New York, NY, February 1999.

Speaker. Distribution reliability for de-regulated utilities. IEEE PES Winter Power Meeting, New York, NY, February 1999.

Speaker. Design for reliability: What level of reliability should distribution systems be built for? Rethinking Electricity Distribution Reliability Conference, INFOCCAST, Atlanta, GA, March 1998.

Panel Member. Value of reliability for distribution systems. DistribuTECH Conference, Tampa, FL, January 1998.

Speaker. Design for reliability: What level of reliability should distribution systems be built for? Rethinking Electricity Distribution Reliability Conference, INFOCAST, Chicago, IL, September 1997.

Speaker. Distribution system design: Reliability and cost optimization. IEEE/PES Seattle Section, Seattle, WA, May 1996.

Speaker. Power system reliability assessment. University of Washington Electric Energy Systems Seminar, Seattle, WA, September 1995.

Project Experience

Consulting and Research Project Experience

Dr. Brown has almost thirty years of consulting experience for utilities and related industries. He has performed consulting services for most of the major utilities in the United States and for many around the world. Specific consulting project experience is available upon request. Major areas of consulting that Dr. Brown has performed include the following:

- Developing asset strategy plans for utilities
- Assessing asset management plans for utilities
- Performing reliability and risk assessments for utilities
- Developing reliability improvement plans for utilities
- Developing system hardening plans for utilities
- Developing equipment failure rate models
- Performing life-cycle cost assessments asset classes

- Investigating the direct and root causes of major utility interruption events
- Performing benefit-to-cost assessments and business case justification for CAPEX and OPEX projects
- Performing safety program assessments
- Performing business management audits for utilities
- Performing applied research projects for utility industry consortiums
- Performing industry benchmark surveys
- Assessing major event performance for utilities
- Performing technology assessments (e.g., Smart Grid)
- Developing system automation strategies for utilities
- Performing distribution system planning and load forecasting studies
- Transmission system planning
- Power system design (e.g., construction documents)

Expert Witness Experience for Regulatory Proceedings

Dr. Brown has over twenty years of experience providing expert witness support in regulatory proceedings for utilities and related industries. He has provided a large amount of prefiled testimony, prepared a large number of expert reports, has given many depositions, and has extensive live testimony experience. Specific information is available upon request. Major areas that Dr. Brown has provided expert witness testimony in regulatory proceedings include the following:

- Assessments of applications for certificates of public need and necessity
- Assessments of commission-mandated reliability targets and penalties
- Assessments of commission-mandated storm hardening requirements
- Benefit-to-cost assessment of overhead-to-underground conversion programs
- Prudency assessment of major capital projects
- Assessment of PURPA avoided cost calculations
- Assessments of utility reliability performance
- Assessments of utility major storm restoration performance
- Assessment of aging infrastructure proactive replacement programs
- Assessment of reliability improvement programs
- Performed industry benchmark studies

Expert Witness Experience for Civil Proceedings

Dr. Brown has over twenty years of experience providing expert witness support in civil proceedings for utilities and related industries. He has prepared a large number of expert reports, has given many depositions, and has extensive live testimony experience. Major areas that Dr. Brown has provided expert witness testimony in civil proceedings include the following:

- Fires and explosions
- Downed utility wires
- Utility car-pole accidents
- Public injuries involving utility equipment
- Utility operational response

- Utility operations and maintenance practices
- Interruptions to large industrial customers
- Patent infringement and validity
- Reliability and power quality of utility customers