Classification of Major Event Days

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Abstract-- A paper that explores the basis, need, and benefit of classifying reliability performance relative to major events. Today, many internal and external goals are set based on reliability performance. Internal as well as external comparison is difficult to make due to variations in weather, collection methods, and a plethora of other variables. The Working Group on System Design has developed a statistics based methodology that classifies reliability data into normal and major event days. After classification, analysis can be performed on each data set using separate processes to arrive at sound business decisions and to make internal comparisons possible. This paper describes the newly developed methodology, the "Beta Method".

Index Terms— Distribution Reliability, Major Event Day, 2.5 Beta Methodology, lognormal statistical approach, Storms.

I. Introduction

Deregulation and re-regulation have led electric utility regulators and customers alike to scrutinize the electric power industry. Claims of improved service for less cost have been used to foster deregulation. Regulators have tried to ensure a continuation, and in some cases, an improvement in electric service reliability under the new operating environment. Electric utility executives have endeavored to continue to maintain service levels without increasing cost, and in some cases, by decreasing expenditures. As a result both internal and external goals have been set around reliability performance, yet there has been no uniform methodology for removing events that are so far away from normal performance that they are known as outliers. Without removal of such events, the variation in annual performance is too great to set meaningful targets. This paper discusses the need to classify reliability performance. Normalizing reliability data will reduce the variability, thus making trending/goal setting possible. It will also segment performance during large-scale events so that appropriate post analysis can be performed.

Distribution re-regulation has been sweeping the country as evidenced[1] by Figure 1.

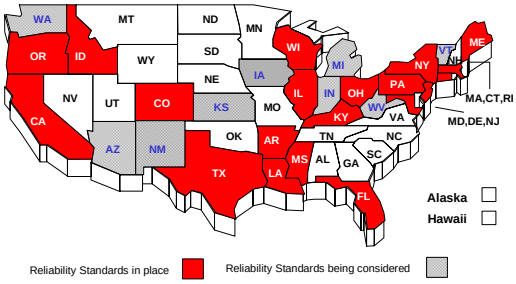

Figure 1. US States involved with distribution reliability regulation.

A few short years ago, only a hand full of states had formal distribution reliability reporting requirements. Today, the number has grown to over half of all US states and is continuing to rise. Some regulators have initiated extensive reporting requirements. Many regulators review not only annual statistics, but also lists of worst performing circuits, reliability expenditures and a variety of other detailed data items. Some states have extended regulatory boundaries to require utilities to purchase outage management systems ("OMS"). It is clear, that executives and regulators alike require a reasonable method for tracking and reporting reliability performance, a method that provides information for proper decision-making.

The IEEE Working Group on System Design, the group that authored the *Full-Use Guide on Electric Power Distribution Reliability Indices-1366-2001*, has recently developed a statistics based methodology (herein referred to as the "Beta Method") for identifying outlying performance (otherwise known as Major Event Days or MEDs). The method is known as the "Beta Method" because of its use of the naturally occurring log normal distribution that best describes reliability performance data, where Beta is a key parameter. Using the Beta Method, utilities can calculate indices on both a normalized and unadjusted basis (identifies abnormal performance). Appropriate decision-making can be performed on each set of indices. Normalized indices provide metrics that can, and should, be used for both internal and external goal setting. Unadjusted indices, when compared to the normalized indices, provide information about utility performance during major events. The Beta method identifies the occurrence of abnormal

This paper was produced by the Working Group on System Design. Please see the last section of the paper for group membership.

[1] *"Reliability on the Regulatory Horizon"* by Cheryl A. Warren and Michael J. Adams, Presented by Charlie Williams at the IEEE T&D Conference in Atlanta 2001.

conditions that grossly affect the reliability of a system and using it allows the investigation of utility performance during major events. Events that may be included in unadjusted information are major weather events, major substation events, or unexpected catastrophic events such as earthquakes. Major events are events that are beyond the design and/or operational limits of a utility. It is anticipated that both executives and regulators will scrutinize those events that cause MEDs and take appropriate action to mitigate their future impact on reliability. There could be cases where no additional action is required, as would be the case when an event was beyond control and beyond the design and/or operation limits of the utility (e.g., Class 4 hurricane).

II. Methodology Development

The Working Group is comprised of over 100 active members from thirty-one states and six countries that hail from universities, utilities, regulatory agencies and consultancies. The Working Group has spent the last two years creating a methodology that would:

- Be fair to all utilities regardless of size,
- Allow segmentation of reliability data into normal and abnormal categories, based on the identification of outlier events that cause Major Event Days,
- Allow use of normalized indices for internal and external goal setting,
- Be consistent for various amounts of data availability and for all utilities, and
- Be easy to understand and execute.

Many working group members anonymously provided their outage data for methodology development. A contingent of volunteer members from the working group performed rigorous analysis on all provided data while evaluating the efficacy of a number of proposed methods. Before the final methodology was chosen, several other methods were developed and abandoned due to their inability to meet the criteria noted above. Rich Christie authored "*Statistical Classification of Major Reliability Event Days in Distribution Systems*", a paper that describes some of the thinking. The working group has selected the Beta Method as the method best meeting the above criteria.

III. The Beta Method

The method is easily applied to reliability data and can be set up to run automatically from an OMS, or be manually applied by using MS Excel™ and/or MS Access™. Its purpose is to allow major events to be studied separately from reliability performance that occurs during what would be considered normal operation, and, to better reveal trends in normal operation that would be hidden by the large statistical effect of major events.

The Beta Method is used to identify major event days. A major event day is a day in which daily SAIDI exceeds a threshold value T_{MED}.

In calculating daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption begins. This technique simplifies calculations and ties the customer-minutes of interruption to the instigating event.

The major event day identification threshold value T_{MED} is calculated at the end of each reporting period for use during the next reporting period. For utilities that have six years of reliability data, the first five are used to determine T_{MED} and that threshold is applied during the sixth year. The methodology follows:

1. Values of daily SAIDI for a number of sequential years, ending on the last day of the last complete reporting period, are collected. Consistency of future results is enhanced if five or six years of data are used, but, if fewer than five years of historical data are available, all of the available complete year, historical data should be used. Use of more than six years of data may distort the effects of major events and minimize the impact of the analysis.

2. Replace any day in the data set that has a value of zero for SAIDI with the lowest non-zero SAIDI value in the data set. (This permits the calculation of the logarithm of a SAIDI value for every day. While not technically precise, this does enhance the overall accuracy and consistency of the method.)

3. The natural logarithm (ln) of each daily SAIDI value in the data set is calculated.

4. The average of the logarithms, α (Alpha), (also known as the log-average) of the data set is calculated.

5. The standard deviation of the logarithms, β (Beta), (also known as the log-standard deviation) of the data set is calculated.

6. The major event day threshold, T_{MED}, is calculated by using the equation:

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

(Note that this value should in theory give, on average, 2.3 major event days per year. In practice, using the donated utility data, higher numbers of major event days per year, from two to eight, are seen. This is not unexpected since the actual data does not conform precisely to the log-normal distribution.)

7. Any day that occurs during the subsequent reporting period with daily SAIDI greater than the threshold value T_{MED} is designated a major event day. The data for this day

should be removed when calculating normal reliability performance.

It is the group's recommendation that major event day performance be reviewed in a different, possibly more rigorous, manner than normal day performance.

SAIDI was chosen as the metric in order to capture the effects on customer minutes interrupted ("CMI") or duration of events. SAIDI is the division of CMI and total customers served. Dividing by total customers served allows utilities to use the methodology even after a merger has occurred. Despite the fact that SAIDI is used as the metric to determine MEDs, the methodology is applied to all indices.

Because the methodology classifies all performance into two data sets, 1) normal performance and 2) abnormal performance, it cannot favor a poorly performing utility. All data is provided in one of the two classifications. It is up to executive management and regulators to review both data sets to draw conclusions about overall performance.

IV. Examples of the Methodology Results

For a detailed calculation example please refer to *Draft 9 of the Full-Use Guide on Electric Power Distribution Reliability Indices 1366-D9.* Using data provided by member utilities, two illustrative examples are presented here. Utility 4 used three years of data to determine threshold values while Utility 10 used seven years of data.

A. Example 1 - Utility 4

Figure 2 and Figure 3 show analysis results from Utility 4. The lower light blue bars show the normalized values for SAIFI and CAIDI. Utility 4 is required to report SAIFI and CAIDI, not SAIDI to their regulator. The upper orange bars show the contribution from abnormal events to SAIFI and CAIDI. The summation of the two bars is the total system SAIFI and CAIDI or unadjusted SAIFI and CAIDI. Note that normalized SAIFI performance was constant, with no more than 3% variation from year to year. The normalized CAIDI was relatively constant, with no more than an 8% variation. Unadjusted, SAIFI varied 11% from year to year and CAIDI varied between 56% and 70% over the period.

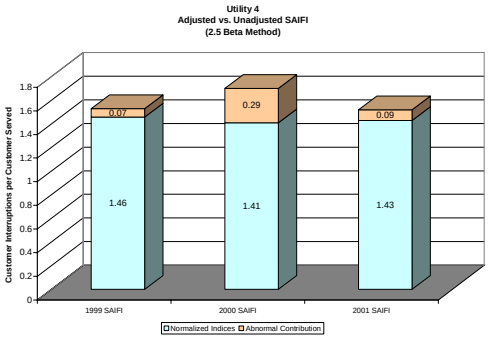

Figure 2. Utility 4 SAIFI

Figure 3 illustrates the significance of identifying abnormal events. In evaluating three years of provided data, it is evident that 2000 had the most major event activity. In this case major event days were caused by weather. For that year (2000), over 42% of the utility's overall CAIDI could be attributed to the abnormal event CAIDI. Notice that normalized CAIDI was fluctuating within a reasonable band (no more than 8% variation from year to year). It is likely that the system is performing within acceptable design and or operational limits. The fact that major event contributions vary from year-to-year is to be expected, and may be directly correlated to weather variations. If the major event variation is due to conditions within the utility's control, then executives and regulators should take appropriate action. . Furthermore, if over time there is indeed a true and sustained change in the weather patterns affecting a utility's service territory, this "normalization" process will reflect (and include) that change. If that occurs, then there are strong and supported reasons for the utility to change it operating practices.

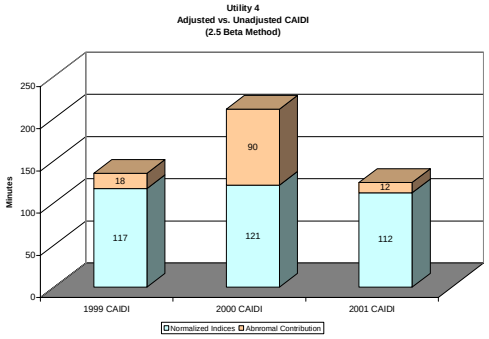

Figure 3. Utility 4 CAIDI

Figure 3 is a clear example of why normalizing indices is critical to customers, regulators and internal utility goals. If the unadjusted data were used to target spending, then this utility might be focused on the wrong issues (e.g., events that occurred as a result of one major storm and are unlikely to occur again in the foreseeable future).

B. Example 2 - Utility 10

Figure 4 and Figure 5 show results from Utility 10. SAIFI, even adjusted, is still increasing at a steep rate, while CAIDI is oscillating and is fairly constant. Given this type of information, executives from this utility may alter spending and action plans if no recent IT systems changes have been implemented that might account for the steep rate of SAIFI change. If this utility recently implemented a fully connected outage management system that more accurately captures reliability information, then these graphs could be explainable by that fact alone. It is well known that after fully connected IT systems are implemented, that reliability appears to worsen since more accurate information is being collected. For this example, we assume that no system changes occurred.

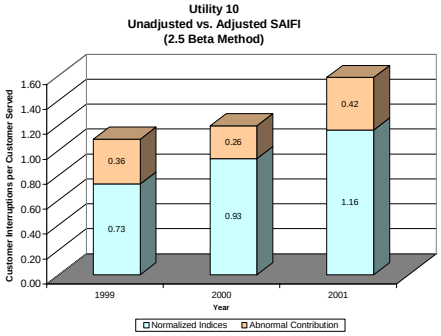

Figure 4. Utility 10 SAIFI

Figure 4 shows unadjusted CAIDI varies as much as 69% while adjusted CAIDI varies only as much as 28% a year for this utility. While 28% is a high percentage, it is significantly better than unadjusted statistics. This information may indicate crew overload on major event days. It appears that the major events were significant enough to completely saturate crew availability and thus restoration efforts were excessively delayed.

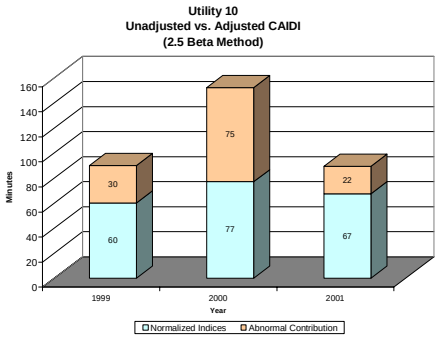

Figure 5 Utility 10 CAIDI

C. Example 3 – Worst Performing Circuits

Many state regulators are requesting reports on worst performing circuits ("WPC"). Typically, all interruption data is used to determine the WPC list. The number of circuits reported to regulators across the US varies from 4% to 10% of the total circuits on the system with each state allowing different reliability data adjustments. There are only a few states, at the present time that review circuit performance based on storm-adjusted or major event classified information. Consequently, utilities may be required to investigate solutions to problems that would only occur during a major event. This may not be the most cost-effective approach. The Beta Method will allow utilities to apply worst performing circuit criteria to adjusted data, thus identifying circuits that are most likely to remain worst performing if actions are not taken. In cases where WPC criteria is applied to all events, circuits often become members of this group due to one extreme event. Using non-classified data seems to defeat the regulatory purpose, which presumably is to solve repetitive reliability issues on problem circuits.

This paper has provided two simple examples using the Beta Methodology. During methodology development, many utilities used the beta method on their own data and determined it to be a fair methodology. It is important to remember that when using the 2.5 Beta Method, ***no data is excluded***, instead it is classified, analyzed and reported upon using separate processes.

V. Benefit Summary

Daily, decisions are made at utilities based on perceived risk versus anticipated reward. The Beta Method provides a mechanism to segment information into appropriate categories allowing different decision paths to occur. It is the hope of this group that classification will result in better business decision-making. Regulators, utilities, and customers benefit from the Beta Method

because it segments reliability performance to reveal trends that utilities can then address.

A large group, with representation from all interested parties, created this methodology. The Beta Method allows utilities and regulators to confidently set goals/targets based on normal, and expected future performance. It also provides a technique to review performance during severe events.

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