

Approved Minutes from SPM 2001

To: Working Group on System Design
CC: Dan Ward, Dan Sabin
From: Cheri Warren
Date: 7/18/2001
Re: Minutes from the Working Group on System Design from the 2001 Summer Power Meeting in Vancouver, BC

68+ members and guests attended the meeting that began at 8 AM.

1. We request a BIGGER room!

The minutes from the WPM 01 were approved with one minor change. The WG web site can be found at: <http://grouper.ieee.org/groups/td/dist/sd/>. We have asked for a secure area since we are using sensitive information in our analyses. These minutes will be posted there once the area is secure. You will be informed by e-mail when the site is ready.

TF on Outage Reporting Practices – Chair Dan Pearson - PGE

This group met from 8:10 to 9:00. Dan was unable to attend this meeting due to the Californian power crisis. The TF paper was submitted in June 01 and hopefully will be presented at the WPM in NYC. Cheri Warren gave a quick introduction to key findings from Dan's survey. Denis Hansen from PacifiCorp gave a presentation on issues relating to outage reporting and issues when using benchmarking tools for comparison.

A presentation was then made by Dennis Hansen of Pacific Corp (Scottish Power) (Dennis.Hansen@pacificcorp.com). The presentation gave a brief overview of Pacific Corp. The presentation then went into the elements of Reliability (Inherency/Redundancy/Recovery). See attached pdf file.

Before Scottish Power bought Pacific Corp, the reliability performance was underreported. The reporting was manual and performed by field personnel filling out forms. After the Scottish Power purchase, the task was to determine the level of underreporting. There were (are) 3 parts to the process (input/process/reporting). In the end, they moved the reporting from the field personnel to the dispatchers. They pay customers for missed commitments. They figured they were under reported by 20% with the paper based system.

Ron Stillman asked how step restoration is tracked.

Mike Sheehan stated that in Washington, customer complaints were used to track performance.

Jim Bouford pointed out that step restorations track the number of customers affected at each point in time and the time off and on for each restoration step.

Charlie Williams pointed out that FPC used 4 measures: SAIDI, MAIFI, Customer Surveys & ????. Plus it is important to inform customers of what caused the outage and when their lights will come back on.

Jim Cheney, APS, Asked how to handle the situation where a circuit lock out occurs, part of the load is restored (by closing CB) and then the CB trips again while restoration is in progress.

Roy Billington stated that it should be handled as 2 separate events.

Jim Bouford stated that it should be handled as 1 event, with the step restorations used to keep track of the times on (&off) and the number of customers affected. Since only a part of the original customers affected were restored, the second CB trip is still part of the original event.

Larry Conrad stated that it should be counted twice.

Another member felt that # events dependant on the cause of the 2nd CB trip .

It was brought up that the next version of the Guide (1366) should include either an example or a short tutorial on this subject (Jim Cheney's question).

Dan Ward suggested that we keep the Guide clean with what and how to calculate indices. How to handle the off/on/off should be in a separate Guide.

TF for Reliability Indices P1366 - Chair Cheri Warren - Navigant Consulting

Special thanks to John McDaniel of DTE and Betty Tobin of Seattle City Light for taking notes during the meeting.

As of 3/2001, 1366-1998 has been upgraded to a Full Use Guide. It is not yet available from IEEE. Dan Ward stated that it usually takes 3 to 4 months from approval until Guides are available from IEEE (which should be soon).

A new PAR for 1366 has been submitted and is to be acted on by the Standards Board in September. This par will enable the group to continue to update 1366 and to change the major event definition.

Thanks to Roy Billington (Roy_Billinton@engr.USask.Ca) for making a presentation on the Canadian Electric Association ("CEA") survey and data collection process. This survey has been on going for 39 years. A copy of the latest survey was passed around for review. US utilities are welcome to participate. To obtain a copy of the restricted results contact:

Canadian Electric Association
1155 Metcalfe Street, Suite 1120
Montreal, Quebec H3B 2V6
Phone 514.866.6121 or fax 514.866.1880 or e-mail filippelli@canelect.ca

Ask for the 2000 Annual Service Continuity Report on Distribution System Performance on Electric Utilities.

Some information about the survey: Customer is defined as a meter, Ontario is pushing for PBR's, Indices used are SAIFI_M(MAIFI), SAIFI, CAIDI & IOR (ASAI?). Another part of the survey deals with classification of outages (causes of outages). As part of the classification,

Adverse Weather (lightning is not included) is defined as weather that stresses the system above the design level. There is also a section by causes and they are shown as # interruptions/100,000 customers. They include G & T and list it under loss of supply. The Ontario Energy Board (OEB) is accepting CEA as the basis for PBR.

Canadian Statistics

	2000	1999
SAIFI	2.26	2.59
SAIFI(M)	1.75	1.54
SAIDI	3.23 hrs	4.31 hrs
CAIDI	1.43 hrs	1.67 hrs

Dennis Hanson asked if anyone audits outage data like in the U.K where the regulator audits collection of interruption data.. Roy Billington said no, because he believes that this (CEA) survey gets “bottom-up” ownership of outage data and that the participants believe that the survey is useful.

The 1998 Ice Storm had little effect on SAIFI, but a huge impact on SAIDI.

Loss of supply is the largest contribution to SAIFI. Charlie Williams asked to clarify what was classified as loss of supply. Roy stated that any non distribution outage was classified as a loss of supply. The FPC system only deals with distribution because that is all they are responsible for.

Mike Sheehan asked how would you handle those customers with a back-up (UPS or Flywheel with a generator). Roy said he didn't know. Dan Ward pointed out that it would be more of an unavailability question, and those customers should be counted in the outage statistics.

Major Event or Abnormal/Normal Data Segmentation

A special thanks to Charlie Williams, Jim Bouford, and Margaret Mackisack for profound contributions to the pre-meeting work, to Clay Doyle who provided data that can be publicly used and to all the members who provided anonymous data for further analysis (you know who you are!). A memo was sent to the working group pre meeting to describe one possible approach to classifying normal/abnormal days. Please see the web site to obtain a copy of that memo.

The rest of the meeting was a discussion on how to define a Major Event. This discussion had 4 parts: Proposed Methodology, Observations, Concerns, questions & Answers, and finally an Open Discussion.

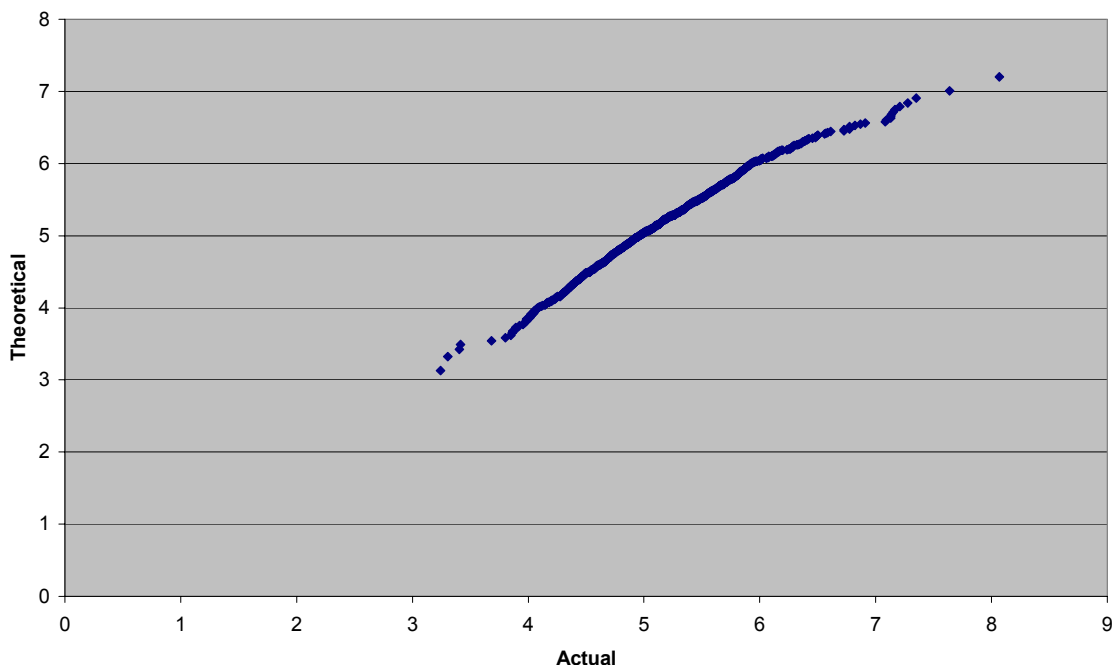
Proposed Methodology:

Use of the current 10% definition is not universally accepted. Also, application of the 10% varies. The NY PSC strongly prefers this method to anything they have seen so far. A memo from them will be posted on the web site. The KS commission also prefers this method. See the web site for a memo from them.

Another possibility is the use of 3 (or some other number) sigma. 3σ is always the same percentage when applied to a Normal Distribution. A Normal Distribution cannot be used to represent interruption data. Sigma varies by the type of distribution. Outage data seems to fall into a log normal distribution as shown in one example below.

For the Log normal distribution, $e^{(\mu + 3\sigma)}$.

Log Normal Another Utility

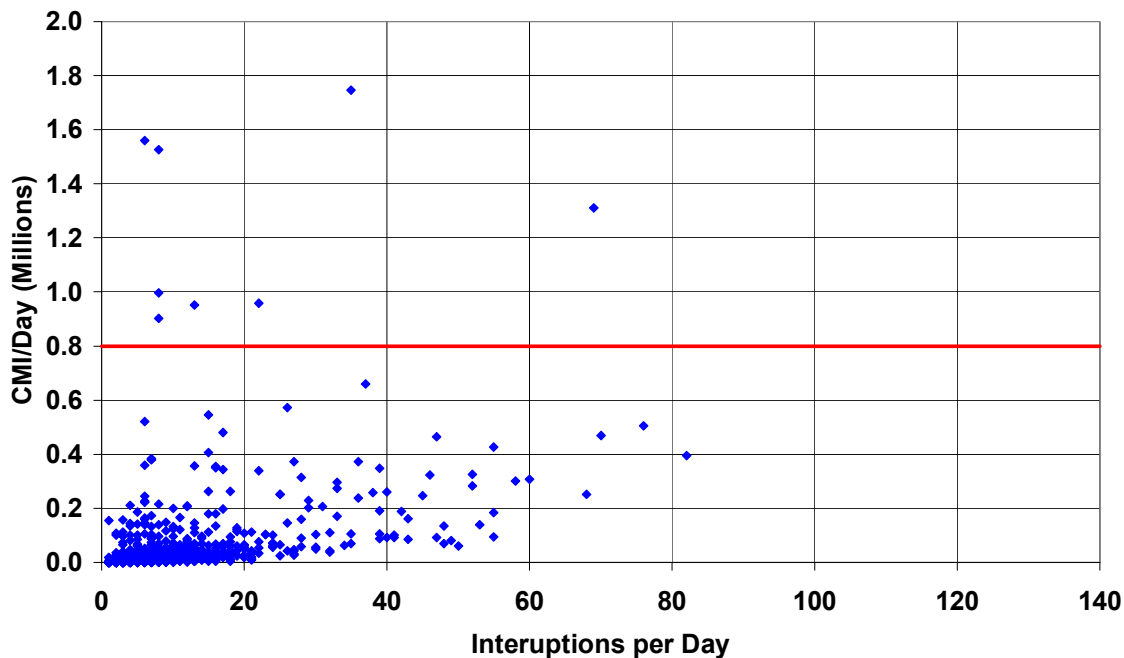


It seems that Utilities and their Regulators cannot agree on a definition. The Task Force wants to strike a balance. Charlie stated that there is a need for commonality because of cross state utilities. Dan Kowaleski pointed out that these cross state utilities are becoming more prevalent due to mergers. Another issues is that there are also various sizes of utilities.

Utilities and Regulators are asking this group to formulate a better definition.

Jim Bouford then gave an example of abnormal versus normal. This was done by showing a plot of Customer-minute Interrupted (CMI)/day vs. the # interruptions/day. This is a scatter plot, for the most part and it shows a pattern. Most of the outages are "grouped" or clustered. There are some outliers, usually with a very high CMI, as compared to the rest of the plot. These high CMI's are beyond the design limit of the distribution system. In most cases, there is a defined boundary (or gap) with normal events on one side and abnormal on the other. With 3 years of data, this gap is evident, but with only 1 years worth of data a pattern can be seen.

Utility 2 3 years of data

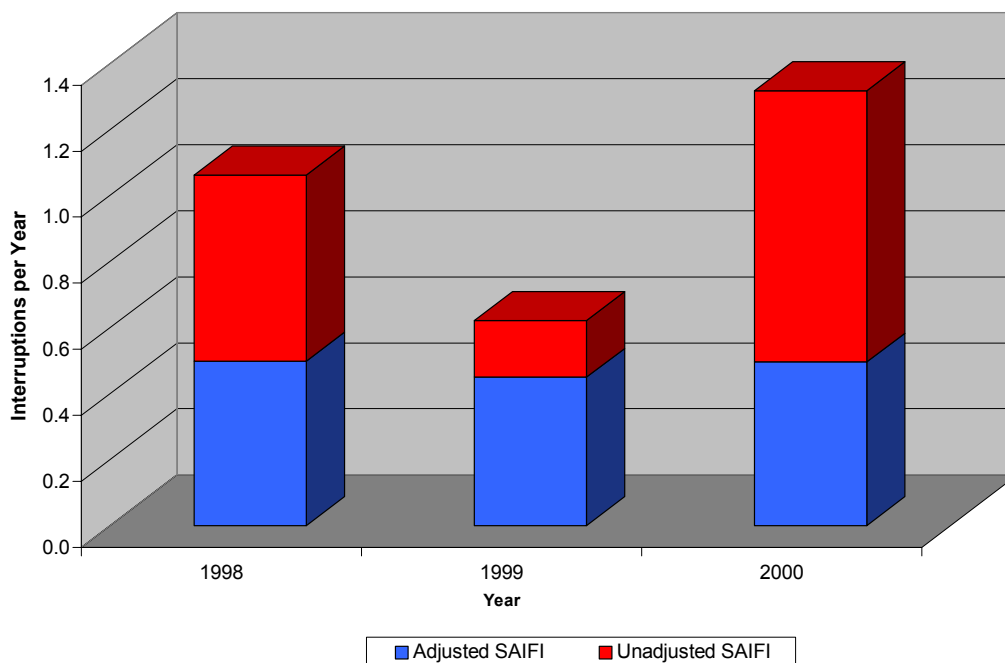


Jim also showed a 3-D example where each interruption is grouped and the axis are: CMI, CI (customers interrupted) and number of interruptions. This plot is more difficult to create and may be of lesser value.

Adjusted/Unadjusted indices would be based on the gap, or break as shown on the CMI vs. # interruptions graph. All interruptions would be included in the unadjusted indices while the adjusted indices would contain only those interruptions considered to be "normal".

The following graph shows the total SAIFI with no segmentation (blue + red bars), normal interruptions (blue bars), and abnormal interruptions (red bars). This view provides all the information, in one graph, that regulators and utility executives may want to review relative to SAIFI.

Performance (SAIFI)



It is important to note that approach classifies data for segmentation, but does not exclude data! The group feels strongly that abnormal interruptions should be rigorously reported upon to the public service commission.

Roy Billington asked how an interruption was defined – answer, any protective device that operates.

The question was asked, how does the 10% over 24 hours line look as compared to the graphs? This was not known as no one had plotted it. The sub group that is working on this in between meetings will take a look at the difference.

Mike Sheehan – Washington does not want the “baseline” changing. They look at (review) normal not abnormal days for their regulator review.

Rich Christie asked where or how are regulators going to place this abnormal/normal line. He was told that a statistical approach was being looked at.

Observations:

Percent by Region and Company from 1 utility was presented. There were several times from a couple of years where 10% of the customers in a region were interrupted in a day and this occurred for several different years. Also, there were some years where not 1 region had 10% of its customers interrupted over a day. As a company, the numbers were much smaller.

Operating Region Basis

	5%	6%	7%	8%	9%	10%
1994	18	14	10	9	8	7
1995	26	13	10	8	5	5
1996	24	18	16	12	10	8
1997	19	16	11	8	8	8
1998	49	43	35	33	27	25
1999	28	13	10	10	9	8
2000	29	24	19	10	9	6

Total Customers Served

	5%	6%	7%	8%	9%	10%
1994						
1995						
1996	2	2	2	2		
1997	2	2	2	1	1	1
1998	7	6	6	6	6	5
1999	2	1	1			
2000	1					

CMI/day vs. # interruptions/day for several utilities were shown. Almost all of them showed a natural break point. 3-D plots were not shown, as in most cases they have provided little additional data.

In Florida, a severe event is either a named Tropical Storm or a confirmed tornado. Outages from those days (for the region affected) are not included in the indices.

Charlie Williams then showed some of FPC's data. From this outage data, it appears that it falls into a lognormal distribution. His data is distribution only – no transmission events! Also, 3% of the days contain 50% of the CMI.

Charlie then showed three 3 years of SAIFI, with 1 portion being that of just "normal" outages and another part of abnormal, or that portion that would be "excluded", in reporting.

Mike Sheehan had a concern about data integrity during storms. Many agreed that in the past things have been less accurate during storms. Some of the new systems are making this less of a problem, but there is a **long** way to go.

John ?? - Question about the 3 years of SAIFI shown, 1 year would have had 2/3 of the SAIFI excluded and what regulators would think of that.

Bob Fletcher– Thinks there is a flaw in drawing lines to exclude abnormal events for day-to-day type data. Thinks it should be based on the utilities performance, not on response to weather. Also, what were the causes and the distribution of the causes.

It was pointed out that each utilities segmentation values would be different.

Segmented events will remove large amounts of CMI just due to the nature of those events.

It was mentioned that the regulators should pick the cut-off point. Also, the regulators should be requesting significant details for each of the segmented events.

Rich Christie stated that a different term (word) should be chosen instead of exclusion. Suggested that classification or segmentation be used instead of exclusion.

Dennis Hanson mention that in the U.K. they exclude data above the 3 sigma mark and replace it with an "average" day.

The group needs the members to work on this (normal/abnormal).

Cheri Warren, Charlie Williams, Rich Christie, Jim Bouford, John McDaniel, Keith Frost, Dennis Hanson, Rodney Robinson agreed to form a sub task force to continue this work in between meetings. If you volunteered and we didn't write you down – drop Cheri a note!

Comments, Question & Answers

Dan Ward asked if it would help to scale the CMI by the number of customers served. It was pointed out that this would be roughly equivalent to SAID per day. Dan also mentioned to look at SAIFI or CAIDI on the y-axis.

Rodney Robinson – How would you handle CMI when the interruption is spread out over multiple days. Cheri Warren said to use the day in which the interruption first occurred. Put all the CMI for the event on that day.

Mike Sheehan stated that what ever the group comes up with, it must be easy to use.

Action Item - Larry Conrad is going to send his companies trigger levels for storm response (they were currently in a level 3) to Cheri Warren for distribution to the group. Others are encouraged to send similar information too.

Dennis Hanson has had to build in 3 definitions of Major Event. 1 each for: P1366, Regulatory and Annual Statistical Definition.

Open Discussion

From Dan Kowaleski (ComEd/PECO concerns):

Management would want to know, what is the cut-off point.

They want to be 1st quartile

Thinks IEEE should take over the reliability surveys & benchmarking so as to standardize it.

Thinks that the 10% should be kept (K.I.S.S.), or some other straight percentage.

What is the definition of an operating region (criteria)?

Rich Christie wanted to know how many major events would be allowed per year. In Illinois, the ICC does not allow exclusions.

System health would become an issue

Dick Hensel pointed out that 10% may not be reached company wide as more and more mergers take place. This would be due to systems size. Also due to Urban versus Rural systems.

Jim ?? said that you cannot use just one index (must use multiple index's).

In Illinois, the utility defines the design criteria (as in temperature for planning purposes).

Rich Christie – Circular between events and Design Criteria.

Gene Baker likes the Red/Blue (Normal/Abnormal) charts, but thinks that the group needs to come up with different names than what were on the slides. Stated that we should choose the word wisely. Also, regulators are concerned (or should be) with both parts.

Roy Billington – should classify outages and try to quantify. He also said that there is a lot in the choice of words.

Rodney Robinson– Does not like the 10% because of the Urban versus Rural. Never normalize in urban areas.

Dave Blew - The group should seriously consider any changes to 1366 since many people are now using it to define regulation and OMS systems.

A question was asked as to the basis of the 5 minute rule for sustained outages. The existing definition was put in place to accommodate protection schemes that required up to 5 minutes to automatically transfer load. The group was asked if the protection schemes have gotten quicker. If they have, we could consider moving to the one minute definition.

Group Action Items:

1. Please send customer definition to Cheri Warren. She will compile and send to group.
2. Please send definition of a momentary to Cheri Warren. Also any comments on the 5 minuteShe will compile and send to group.
3. Data Request. We'd like to further the efforts that have been started. If you can participate, please send us the following data for as many years as you have it in the format shown:

Date	#Interruptions/Day	CMI/Day (Millions)	CI/Day (1000s)
1/1/1998	550	110.234	23.33
1/2/1998	302	22.167	13.78

To get data like this, you can use an access summary query that summarizes number of interruptions (lines of outage history data) and customer minutes interrupted (CMI).

Also, please provide the customers served per year. Let Cheri know if you are willing to share this data with the task force or only with her. When data comes to in, she will make it

anonymous in name. Any questions – call her at 518.281.9648 or e-mail at cwarren@rcgroup.com

We intend to convene the sub task force in between meetings to continue the work on abnormal/normal.

**TF on System Design from a Reliability Perspective - Chair Jim Bouford
National Grid**

This task force abdicated their time for the major event discussion. They expect to meet during the next WPM meeting.

New Business

None.