Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

October 29, 2010

BY COURIER

Ms. Kirsten Walli
Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700,
Toronto, ON, M4P 1E4

Dear Ms. Walli:

EB-2010-0249 – OEB Consultation on Distribution System Reliability Standards – Hydro One Networks' Comments in the Initiative to Develop Electricity Distribution Reliability Standards

Hydro One is very supportive of this important initiative to develop Electricity Distribution Reliability Standards. The Company appreciated the opportunity to participate at the stakeholder session on October 15, 2010. At that session there was a consensus, as illustrated in both the jurisdictional reliability research and the customer survey as well as through the stakeholder participant's comments, that this is not the time to develop new Codes to address electricity system reliability. This is not a key issue for customers at this time when "Ontario's electricity market is highly cost-conscious" as outlined in the Pollara report. Customers are not interested at this time in paying more for better reliability though they do want to maintain existing reliability levels. Also, the industry is on the cusp of having new tools such as smart meters and smart grid that are expected to enhance the capability to improve reliability in three to five years.

Therefore, at this time, Hydro One recommends maintaining the reliability metrics that are currently reported. The Company recommends that the OEB continues to use a "target" system for regulating reliability performance (with action plans required to be submitted when the target is not met) rather than a "Monitoring" system or a "Penalty/Reward" system. This current system appears to be working well and is satisfactory to the customers of Ontario.

If the Board does determine that they want to investigate major changes in the industry's reliability standards Hydro One recommends that a Working Group be established to fully investigate any changes to the current standards. This investigation would include, for example, looking at other jurisdiction's approaches to benchmarking; their experiences with other reliability standards; as well as utility specific circumstances such as distribution system configuration; geography; weather; and customer density. Hydro One does support some minor changes to the reporting metrics that would include:

1. Targets in future could be based on a 5 year standard versus the current 3 year standard.

2. Cause code statistics could provide further detail as to the origin of the interruptions. Electricity utilities are currently required to track (but not report) interruptions by "cause code". Reporting this metric will require a consistent approach and may necessitate utilities to review their data collection practices concerning outages.

3. If the desired outcome is to improve the average experience of all customers based on the assets to serve them, metrics such as Customer Hours/km and Customer Interruptions/km are useful as they relate to the average experience of both the customer and the performance of the asset, taking into account:
    a) The customer experience (how many were impacted);
    b) The utility response (how long, how many customers are without power); and
    c) The assets to deliver the power (km of lines).

    Note: It is possible for the Board to calculate these indexes as the Board collects all data that are used in the equations.

4. The desired outcome should also be to improve the experience of customers with poor dependability. Metrics such as Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Durations (CELID) lead the utilities to improve assets on specific parts of the system. Details regarding how these metrics can be measured are described in our answers to Board questions below.

Care should be taken in determining "normalizers" due to the impact of very large events. The IEEE 1366 methodology has issues that at this point have not been resolved. Research has shown that there is no physical reason why a daily reliability index can be automatically assumed to be log-normally distributed. Also in terms of the performance patterns of the data, the IEEE 1366 methodology is not reasonable based on the fact that the log-normal distribution does not fit the part of the data curve that is significant for this process (the right tail of the curve) for all utilities.

The following are Hydro One's responses to the specific issues identified for discussion by the OEB.

Attachment A (From October 7th, 2010 the OEB Letter)
Issues for Discussion

Setting Reliability Requirements

What improvements could be made to the current system reliability regulatory regime in Ontario?

Hydro One recommends maintaining the reliability metrics that are currently reported. The Company recommends that the OEB continues to use a "target" system for regulating reliability performance (with action plans required to be submitted when the target is not met) rather than a "Monitoring" system or a "Penalty/Reward" system. This current system appears to be working well and is satisfactory to the customers of Ontario.

In addition to SAIDI, SAIFI and CAIDI, what other system reliability measures could be used by Ontario distributors to more accurately monitor system reliability performance?

The traditional measure of frequency (SAIFI) and duration (SAIDI) are based on the average performance of the system for an average customer. While CAIDI is fairly common as well and is perhaps useful within a utility as an indicator, its calculation can lead to fallacious conclusions such as where SAIFI and SAIDI are both improving but unevenly leading to an increase in CAIDI. It also gives an average restoration time for an average customer and does not take into account the configuration of the distribution system or the nature of the interruptions.

SAIDI and SAIFI measure the average time an average customer is without power and the average number of times an average customer's power is interrupted. These metrics do not show the reliability of specific assets. The reliability of specific assets should consider whether they are "Suitable or fit to be relied on; worthy of dependence or reliance; trustworthy." Customer Hours/km and Customer Interruptions/km are a set of components that relate the average experience of both the customer and the performance of the asset, taking into account:

a) The customer experience (how many were impacted);
b) The utility response (how long, how many customers are without power); and
c) The assets to deliver the power (km of lines).

As mentioned earlier, CEMI and CELID can be calculated if a utility has a connectivity model linked to its customer data (which is required to accurately calculate SAIDI and SAIFI). These metrics can be compared internally within the utility, or to other comparable utilities based on percentage of customers affected. For example, the percent of customers interrupted more than "x" times or the percent of customers interrupted more than "y" hours.

The use of MAIFI (Momentary Average Interruption Frequency Index) is inappropriate for Hydro One since we do not currently have the capability to measure momentary interruptions on all the automatic restoration equipment on the distribution feeders.

On what basis should a reliability requirement be established?

Reliability requirements should be reflective of the specific circumstances faced by individual utilities (distribution system configuration, geography, weather, customer density, customer willingness or ability to pay) and of the electric utility's ability to affect performance. The reliability requirement should focus on ensuring that assets for all customers provide a certain minimum standard of reliability. This reliability requirement would specify the minimum number of outages and maximum durations for all customers.

Some jurisdictions have restoration standards that apply during major events. Would establishing such restoration standards for Ontario distributors be appropriate and effective?

Restoration standards would vary too much and more time would be spent on speculation and opinion to be effective. A report from the affected utility on its response procedures to a major event could be produced for review by the OEB to ensure appropriate actions were taken.

Historic conditions must also be considered as design criteria concerning reliability has evolved and not all existing facilities would be able to meet the requirements of a new reliability standard.

Board audits have shown that the length of an outage is highly dependant on how quickly crews can arrive at the scene of the outage. The actual time to repair the system often comprises only a small portion of the length of the outage. Would establishing a standard related to crew response times be appropriate and effective?

There should not be a crew response time standard (other than the present emergency response measure). A new standard would limit the ability of utilities to improve the system through automation. Investment in Smart Grids may change the whole process for power restoration on the distribution system.

Surveys indicate that 82% of residential and 69% of business customers do not call in to report an outage. However, distributors' responses indicate that they still rely heavily on customer calls to know about an outage. As part of a program to improve reliability results, should distributors consider ways to improve or encourage customer reporting of outages? What other steps could be taken?

Smart meters may in the future be able to be used to identify customers without power.

Surveys also indicate that improving distributor communication to customers during an outage, improves a customer's satisfaction and/or tolerance of an outage. Should the Board consider instituting requirements relating to improved communication? (For example, a distributor may be required to be able to inform customers about the cause of an outage and expected restoration time, within an hour of the outage occurring.)

Keeping customers informed of the status of an outage is important to Hydro One. Among Hydro One customers that were given an estimate time of restoration, our market research shows call satisfaction of 81% if the outage is restored before the estimated time. Satisfaction drops to 56% if it is restored later than the estimated time.

Utility crews do not know what the cause of the outage is until they arrive at the site(s) (other than forced, planned and occasionally motor vehicle accidents) so this is not an appropriate metric since it may take more time to update the notification systems instead of restoring the power. Utilities would be able to say if the cause was planned or forced. Greater detail comes after the interruption has been restored.

Hydro One would be pleased to provide more in-depth information regarding our interaction with customers during outages as well as other customer communication and research that deals with reliability.

What other issues should the OEB consider when developing formal system reliability requirements?

As noted earlier, the reliability requirements should recognize asset based measures such as customer interruptions or customer hours of interruptions per line length and also point to potential areas where reinforcing the system is required.

Setting Performance Targets

What types of approaches should be considered for setting a performance target for reliability metrics?

Most of the traditional reliability approaches focus on average system dependability measures. A specific customer view of the impact of outages on both frequency and duration should be emphasized. See the previous answers referring to Customer Interruptions and Hours per km, CEMI and CELID.

Should the Board establish a province-wide performance target for each measure or individual targets for each distributor?

At this time, individual targets or improvement levels would be more effective for each utility.

Should different targets be set for different classes of customers? (For example, should a higher target or different target be in place for large users vs. residential customers?)

Setting higher targets for some classes of customers implies lower service for others. Setting standards based on usage could only be justified if a premium was paid. Also, it would not be possible to implement for most feeders as there is a mix of customers on the feeders making it very difficult to set different targets for different classes of customers served on the same feeder.

Normalizing Results

What approaches should distributors use to normalize results for force majeure and other major events?

Where possible the normalizing of results should be based on cause not impact.

The merging of the concept of force majeure and major events has led to a misapplication of the process of measurement.

Force majeure has been used to identify incidents outside of the control of the utility. The IEEE 1366 major event identification is a statistical tool to isolate non-standard events for calculation purposes. However, the major event could have been due to a range of items from a single tree interruption on a feeder to thousands of customers being impacted by a large storm passing through Ontario. Therefore all force majeure results should be identified separately and all other incidents regardless of size included in the reliability statistics.

<u>*Would the IEEE Standard 1366 be the most effective way to recognize the impact that force majeure or major events have on system reliability performance?*</u>

No.

Care should be taken in determining normalizers due to the impact of very large events. The IEEE 1366 methodology has issues that at this point have not been resolved. In terms of the performance patterns of the data, the 2.5 Beta Methodology is not reasonable based on the fact that the log-normal distribution does not fit the part of the data curve that is significant for this process (the right tail of the curve) for all utilities. Please refer to Attachment 1.[1]

In Attachment 1, the "Major Event Day Segmentation" by R. Billinton, (who is an internationally respected expert in distribution reliability) he explains why it is not appropriate. His comments include:

> "This letter illustrates some of the shortcomings associated with the Beta Method and particularly the assumption that the daily performance index of an electric power utility can automatically be assumed to be log-normally distributed."
>
> "There is no physical reason why a daily reliability index can be automatically assumed to be log-normally distributed. A series of Weibull distributions with varying shape parameters are presented in this letter. The differences in shape are illustrated using the cumulative probability values of the distribution. "

<u>*If not the IEEE Standard, what other approach should be considered as a way to recognize the impact that force majeure or major events have on system reliability performance?*</u>

Force majeure events should be listed by the utility and examined for validity by the OEB using industry precedents and if considered valid, reported separately in the reliability results.

<u>*To what degree will smart metering data impact the ability to monitor reliability performance?*</u>

For Hydro One, the impact is not known at this time.

Sincerely,

ORIGINAL SIGNED BY ALLAN COWAN FOR SUSAN FRANK

Susan Frank

Attach

[1] Attachment 1 included the following documents "Major Event Day Segmentation" by R. Billinton and J. Acharya, "Investigation of the 2.5 Beta Methodology" by N. Hann and C. Daly and "Study of IEEE 1366-2003 2.5 Beta Methodology" by R. Jones.

Major Event Day Segmentation

Roy Billinton, *Life Fellow, IEEE* and
Janak R. Acharya, *Student Member, IEEE*

Abstract **— A wide range of methods has been proposed to define a major event. The most recent approach is designated as the Beta Method and was developed by the IEEE Working Group on System Design. This letter illustrates some of the shortcomings associated with the Beta Method and particularly the assumption that the daily performance index of an electric power utility can automatically be assumed to be log-normally distributed.**

Index Terms **— Major event days, performance index distributions, log-normal, Weibull distributions.**

I. Introduction

Significant disturbances that exceed the accepted system design criteria and operational limits of an electric power utility are usually designated as major events and examined in considerable detail. Weather related disturbances are probably the most common major events and can take many forms. High winds, snow and ice, extreme precipitation and hurricanes etc. can create system stresses that greatly exceed the system design criteria [1]. A wide range of methods has been proposed to define a major event. The most recent approach is designated as the Beta Method [2] and was developed by the IEEE Working Group on System Design. This method is considered to be applicable to all utilities regardless of size and facilitates the removal of abnormal day events from the annual performance data. The Beta Method is a statistical approach that does not specifically consider the system design criteria or the system resource levels available to combat the major event. This letter illustrates some of the shortcomings associated with the Beta Method, and particularly the assumption that the daily performance index of an electric power utility can automatically be assumed to be log-normally distributed.

There are two basic problems associated with the Beta Method. The first is that it is a purely statistical method that does not consider the actual system design criteria and the physical stresses to which the system was exposed. It is also based on the SAIDI/day parameter and therefore also involves the system resources used to combat the effect of the major event. It simply states that if the SAIDI/day exceeds an arbitrary value then the day should be classed as a major event day.

The second problem is that the Beta methodology is predicated on the assumption that the daily reliability index (SAIDI/day) is log-normally distributed. There is no physical reason why the daily SAIDI should be automatically assumed to be log-normally distributed. This is a major assumption and requires that those days which experience no interruptions be removed from the daily index population. The natural log of zero is undefined and therefore cannot be accommodated in the assumed distribution. It has been reported by a number of small utilities that they have a significantly large number of days without any outages [3].

II. Reliability Distributions

Research shows that reliability indices can have a wide variety of distributions [4]. The reliability index distributions differ due to topological changes, operating policies, maintenance practices and sizes of systems. The Weibull distribution is an important distribution in general statistical analysis and reliability evaluation due to its flexible nature. It has one very special feature; the distribution has no fixed shape. The shape is characterised by the values of the parameters in the function. The Weibull distribution is therefore used simply as an example in this letter. Similar analyses could be conducted using other distributions

Fig. 1 shows the probability distributions for various shape parameters (γ). The distributions of the natural-log of the same samples are shown in Fig. 2. The shapes of the distributions are similar to that of the standard normal distribution, but are not completely symmetrical. This is illustrated by comparing the cumulative probabilities of each distribution with that of the standard normal distribution. Table I shows the respective cumulative probability values associated with each distribution shown in Fig. 2. The parameters α and β given in the first column refer to the mean and standard deviation of the corresponding distributions. Table I shows that the probability of a value exceeding a specified level i.e. $\alpha+0.5\beta$, is different for each distribution and that all the Weibull generated values are different from the normally distributed values.

Table II shows the number of standard deviations that yield the same probability value for all the associated distributions. This factor has the same meaning as the β coefficient in the SAIDI threshold in the Beta Method. The coefficients in the first column in Table II give the probabilities in the second column for the normal distribution. The remaining columns show the multiplying factors, or the coefficients of β , in order to provide the same probability.

The results shown in Table II indicate that the utilization of the same multiplying factor for all kinds of distributions will result in different numbers of major event days. In other words, the number of segmented major event days will be more in the case of a normal distribution than for the other distributions if the same β coefficient is utilized. In conclusion, the beta methodology will allot different numbers of major event days for utilities operating under the same conditions but having different performance index distributions.

. It is important to appreciate that decisions regarding major event day determination are based on the probabilities associated with the tail of the assumed distribution. This is an important point.

III. Conclusions

Exceptional abnormal events that cause a significantly large number of customers to be without power for an extended time are generally categorised as major events. These events can significantly impact the system reliability indices. Many regulators allow exclusions based on the reasoning that the capability of a utility during storms does not reflect the true everyday performance. There is, however, no specific boundary value which segments a major event day from the normal days. The actual boundary should recognize the specific accepted system design criteria and the utility response to the major event.

There is no physical reason why a daily reliability index can be automatically assumed to be log-normally distributed. A series of Weibull distributions with varying shape parameters are presented in this letter. The differences in shape are illustrated using the cumulative probability values of the distribution.

REFERENCES

[1] IEEE Standard 1366-1998, "IEEE Guide for Electric Power Distribution System Reliability Indices", 1998.

[2] IEEE Standard 1366-2003, "IEEE Guide for Electric Power Distribution System Reliability Indices", May 2004

[3] C. A. Warren and R. Saint, "IEEE Reliability Indices Standards, Major Event Day Calculations and How They Relate to Small Utilities," IEEE Industry Applications Magazine, Vol. 11, Issue. 1, pp. 16-22, Jan/Feb 2005.

[4] R. Billinton, L. Cui, Z. Pan and P. Wang, "Probability Distribution Development in Distribution System Reliability Evaluation," Journal of Electric Power Components and Systems, Vol. 30, No. 9, pp. 907-916. September 2002.

[5] N. T. Kottegoda and R. Rosso, "Statistics, Probability and Reliability for Civil and Environmental Engineers," McGraw-Hill, NY, 1997.

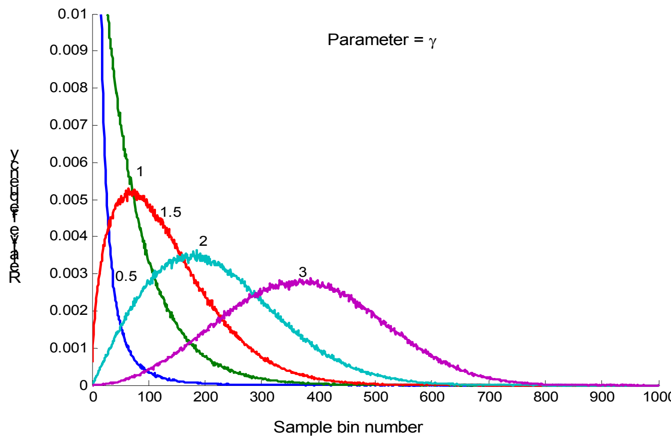

Fig. 1. Distribution of the Weibull samples

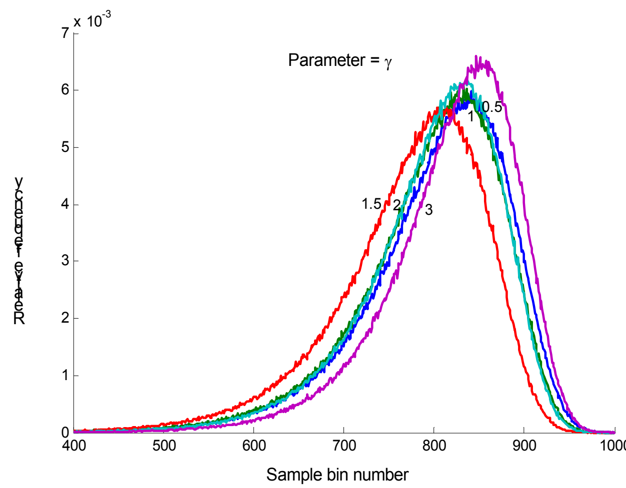

Fig. 2. Distribution of the natural-log of the Weibull samples

APPENDIX

TABLE I
COMPARISON OF THE CUMULATIVE PROBABILITIES FOR DIFFERENT DISTRIBUTIONS

Sample value greater than	Normal distribution	Weibull data distributions				
		γ = 0.5	γ = 1.0	γ = 1.5	γ = 2.0	γ = 3.0
$\alpha + 0.0\beta$	0.5000	0.5702	0.5703	0.5704	0.5706	0.5706
$\alpha + 0.5\beta$	0.3085	0.3442	0.3445	0.3440	0.3446	0.3444
$\alpha + 1.0\beta$	0.1587	0.1324	0.1323	0.1322	0.1324	0.1321
$\alpha + 1.5\beta$	0.0668	0.0214	0.0213	0.0212	0.0215	0.0216
$\alpha + 2.0\beta$	0.0227	0.0007	0.0007	0.0007	0.0007	0.0007
$\alpha + 2.5\beta$	0.0062	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE II
NUMBER OF STANDARD DEVIATIONS FROM THE MEAN OF THE RESPECTIVE DISTRIBUTION

Coeff. of β	Cumulative probability	Multiplying factor for the transformed Weibull distributions				
		γ = 0.5	γ = 1.0	γ = 1.5	γ = 2.0	γ = 3.0
0.0	0.5000	0.1631	0.1644	0.1645	0.1650	0.1648
0.5	0.3085	0.5776	0.5767	0.5762	0.5765	0.5763
1.0	0.1587	0.9267	0.9264	0.9267	0.9266	0.9255
1.5	0.0668	1.2261	1.2259	1.2258	1.2260	1.2262
2.0	0.0228	1.4887	1.4872	1.4892	1.4863	1.4864
2.5	0.0062	1.7200	1.7248	1.7169	1.7180	1.7210

Investigation of the 2.5 Beta Methodology

Norm Hann and Caitlin Daly

Abstract **– The 2.5 Beta Methodology was developed with the intent of providing a reasonable way to define a major event day with respect to distribution reliability performance. According to this methodology, it is valid only if a utility's reliability data completely follows the log-normal distribution, particularly with respect to the tails. This letter shows that this is not the case for a data set provided by a utility and may not be the case with other utilities. Problems arise when the right tail of a utility's data set does not fit the log-normal distribution. The threshold in the 2.5 Beta Methodology will vary since it is dependent on a utility's reliability data from the previous five years. As a result, extremely catastrophic events, reflected by a large SAIDI value, will cause an unsuitable increase in the threshold.**

Index Terms **– 2.5 Beta Methodology, classification, distribution reliability, log-normal distribution, major event days, statistics.**

I. Discussion

Roy Billinton wrote an IEEE Letter entitled "*Major Event Day Segmentation*" [1] which outlined the flaws associated with the 2.5 Beta Methodology. In particular, he discusses the problems that arise when assuming the daily reliability index for each utility is log-normally distributed. Further investigation into the development of the 2.5 Beta Methodology revealed that the log-normal distribution was chosen to be the best distribution that describes reliability performance data by using sampling data from anonymous utility groups in the late 1990's and early 2000's [2]. In an IEEE Paper entitled "*Statistical Classification of Major Reliability Event Days in Distribution Systems*" [3], author Richard Christie admitted that not all utilities have data that follow the log-normal distribution. More importantly, he states that the logic behind the 2.5 Beta Methodology "relies on evaluating small probability values in the extended tails of probability distributions. The shape of the tail is determined by the fit of the entire distribution. A good fit for the distribution may not be all that good for the tail." With this in consideration, a sample of a utility's data was evaluated against the log-normal distribution with ample concentration on the right tail.

To check the fit of a data set with a probability distribution, Christie suggested the use of probability plots. The probability plots used in Figs. 1 and 2 compare the distribution of a the utility's data to the log-normal distribution by plotting their quantiles against each other. A quantile is a value that divides the total frequency of a sample or population into a given number of equal proportions. If the two distributions being compared are similar, the points in the probability plot will approximately form a linear line. As one can see in the plots, the log-normal distribution is not a complete fit for the utility's data.

After making the above observation, the utility's data was transformed to the normal distribution through the use of the natural logarithm. Since the 2.5 Beta Methodology is concerned with the right tail end of the distribution, it is important to analyze the fit of the data in this area. By standardizing the utility's transformed data, it was found that 1.64% (30 days over the five year period) of the YR 1 - 5 data values fall above 2.5 standard deviations of the mean. Similarly, 1.75% (32 days) of the YR 2 - 6 data values fall above 2.5 standard deviations of the mean. However, for the normal distribution, 0.62% (approximately 11.32 days) of the data values should fall 2.5 standard deviations above the mean. This suggests that the right tail of the utility's transformed data set is significantly heavier than the right tail of the normal distribution. Table I illustrates the differences between the normal distribution and the utility's transformed data at various standard deviations above the mean. Clearly, the right tail of the logarithmically transformed data set does not fit the normal distribution. This may be the case for other utilities. Our literature survey does not indicate that any other research has been done in this area at this time. Furthermore, Billinton said that "research shows that reliability indices can have a wide variety of distributions. The reliability index distributions differ due to topological changes, operating policies, maintenance practices and sizes of systems." Therefore, it is not safe to assume that the log-normal distribution provides the best fit for all utilities' data sets. This is especially true for the tails.

When a data set has a heavy right tail, it is often the case that it contains a high number of outliers. The heavier the tail, the more outliers. The outliers existing in the right tail of a data set contribute to larger values of the mean and variance, resulting in an increase in the threshold value. This is undesirable for a utility, as it is an unfair reflection of the utility's normal performance due to large random events.

Through experience, a utility found that a series of bad storms in 2004 raised the threshold in 2005. These storms were 7 or 8 standard deviations away from the mean. In 2005,

The authors are with the Performance Management Department, Hydro One Inc, ON M5G 2P5, Canada (e-mail: norm.hann@hydroone.com).

they were hit by a very large storm, which would have raised the threshold even higher in 2006. Unfortunately for this company, these major events contributed to a significantly high threshold for five years. This raises another problem with the 2.5 Beta Methodology. The natural logarithm transformation is used to normalize data and disperse the weight equally amongst data values. However, in this company's case, outliers still exist in the "normalized" data set. Outliers, like these major storms and hurricanes, will skew the mean to the right and inflate the standard deviation. The same is true for the provided sample data set. This will cause the threshold to be a larger value than it would be if the data was truly log-normally distributed.

Another shortcoming of the 2.5 Beta Methodology is that the threshold is not consistent over the years. This is a disadvantage as the same events may be considered normal for one year, but a major event another year. This is illustrated in Fig. 4. The arrows drawn in Fig. 4 identify 9 days that are classified as major event days under the YR 1 threshold, but are considered normal days under the YR 2 threshold. This number increases as the value of the threshold increases. In addition, it is important to note that a few major event days in YR 1 contributed to the dramatic increase of the threshold in YR 2. This visually illustrates the degree of influence outliers can have on the value of the threshold. Since these outliers represent high values of SAIDI, one should question whether the factors influencing this measure are appropriate reasons for an increase in the threshold value. These factors may include storm intensity and duration (one or more days overlapping midnight), which can be mitigated through design and system changes, while others are a direct result of the utility's operations, such as crew availability, road access, and material availability. It would be unreasonable to say that the performance of a utility during an extremely catastrophic event is "normal". Therefore, it should not have such a huge effect on its future performance threshold. Clearly, the threshold value is a measure of utility response and damage, rather than the impact an event has on the utility's normal performance.

II. Conclusions

In terms of the performance patterns of the sample utility's data, the 2.5 Beta Methodology is not reasonable based on the fact that the log-normal distribution does not fit the right tail of the data. This was a concern raised by Christie when he noted that "a good fit for the distribution may not be all that good for the tail." [3] The work of Billinton confirms that the distribution of a reliability performance index varies amongst utilities [1]. Furthermore, it would be prudent for other utilities to examine their data for goodness of fit in the right tail section of the log-normal distribution curve.

III. Appendix

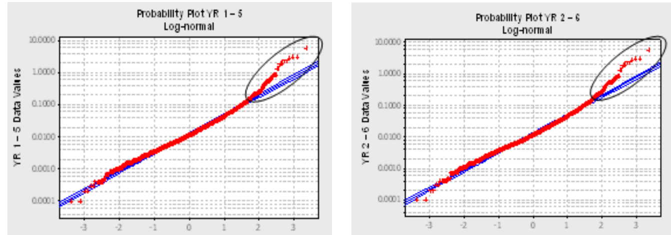

Fig. 1 & 2. Probability plots for a sample utility's data vs. log-normal distribution

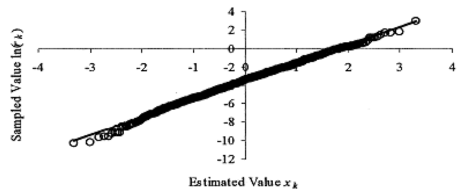

Fig. 3. Probability plot that Christie used to demonstrate a good fit with log-normal distribution [2]

TABLE I
COMPARISONS BETWEEN THE NORMAL DISTRIBUTION AND A SAMPLE UTILITY'S TRANSFORMED DATA SET

Number of Standard Deviations Above the Mean	Normal Distribution		Utility A YR 1 - 5 Transformed Data		Utility A YR 2 - 6 Transformed Data	
	Percent of Data Values Above the Mean	Number of Days Above the Mean	Percent of Data Values Above the Mean	Number of Days Above the Mean	Percent of Data Values Above the Mean	Number of Days Above the Mean
1.0	15.87%	289.79	14.45%	264	14.40%	263
1.25	10.56%	192.82	9.74%	178	9.86%	180
1.5	6.68%	121.98	7.06%	129	7.06%	129
1.75	4.01%	73.22	4.65%	85	4.82%	88
2.0	2.28%	41.63	3.45%	63	3.34%	61
2.25	1.22%	22.28	2.03%	37	2.19%	40
2.5	0.62%	11.32	1.64%	30	1.75%	32
2.75	0.30%	5.48	1.26%	23	1.26%	23
3.0	0.13%	2.37	0.82%	15	0.82%	15
3.25	0.06%	1.10	0.60%	11	0.60%	11
3.5	0.02%	0.36	0.49%	9	0.49%	9

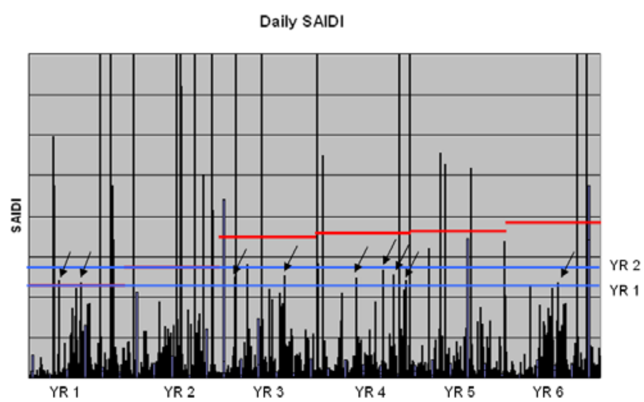

Fig. 4. SAIDI data for a sample utility's data set

IV. References

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Study of IEEE 1366-2003 2.5 Beta methodology provided via email from Robert Jones – Oncor Electric Delivery, Texas, USA

The basic assumption when using the IEEE 1366-2003 2.5 Beta method is that the daily SAIDI values follow a lognormal distribution. I believe that before fully implementing this methodology, the lognormal distribution assumption should be validated. I have access to five years of confidential SAIDI values from 2005 to 2009 for several utility companies and was able to plot them against a lognormal curve. While the distribution is similar to a lognormal and indeed, a lognormal distribution is the "best" fit, there are statistically significant differences between the SAIDI distribution and a lognormal distribution. A representative plot is shown in Figure 1.

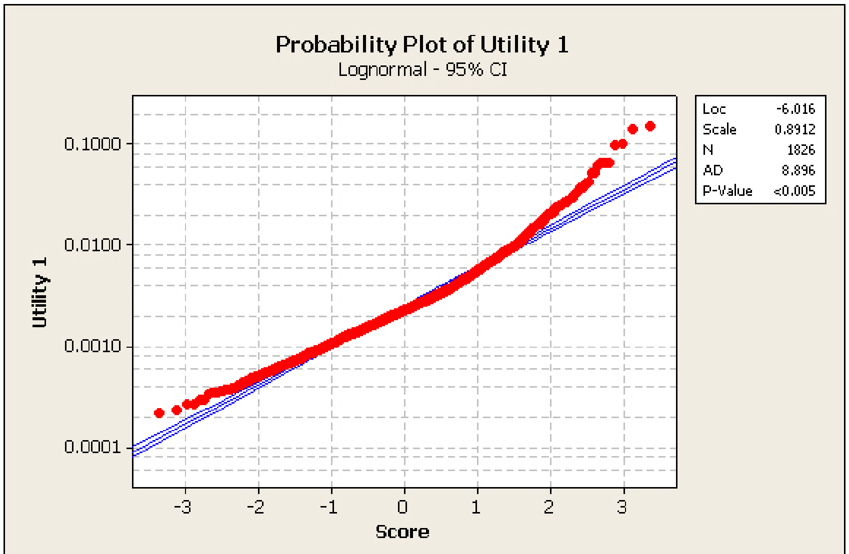

Figure 1 - Representative Lognormal Comparison Plot

The red dots on the plot show the actual daily SAIDI values from 2005 to 2009 while the blue lines show the true lognormal and the 95% confidence interval. The dots follow the lognormal distribution closely in the center range but vary significantly in the upper tail and to a lesser extent in the lower tail. This indicates that the utility had outages of longer duration than the lognormal distribution predicted. Also, the p-value is less than 0.005 indicating that there is a statistically significant difference between a lognormal distribution and the SAIDI distribution.

The analysis was done on 11 utility companies that represent multiple regions of the U.S and all showed a similar result. All had a p-value that was less than 0.005 indicating that all utility SAIDI distributions were statistically different from a lognormal distribution. All curves were similar to the one shown here. Some showed even greater variations in the tails.

There is evidence that suggests that the SAIDI distribution does not fully conform to a lognormal distribution. Since this is a basic assumption for the 2.5 Beta method and is critical for obtaining useful results, I recommend further study on the true SAIDI distribution by analyzing a broader range of utilities before the 2.5 Beta method is implemented.

Robert H. Jones, Ph.D.
Oncor Electric Delivery