Ontario

Ontario Energy Board
Commission de l’énergie de l’Ontario

Report of the Board

EB-2015-0182

Electricity Distribution System Reliability: Major Events, Reporting on Major Events and Customer Specific Measures

December 7, 2015

TABLE OF CONTENTS

A. INTRODUCTION

A.1 – Background

On August 25, 2015, the Ontario Energy Board (OEB) issued a Report of the Board: Electricity Distribution System Reliability Measures and Expectations. This Report set out the direction that is being taken by the OEB to establish an expected level of electricity reliability performance by distributors.

Specific reliability performance objectives will set the level of performance a distributor is expected to deliver. Continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or maintain the same level of performance at a reduced cost.

The OEB will continue to use the system reliability indicators that are part of the performance Scorecard: the "Average Number of Hours that Power to a Customer is Interrupted" and the "Average Number of Times that Power to a Customer is Interrupted. (SAIDI and SAIFI[1] respectively)

A set of measures with baselines[2] will be established for each distributor, based on its' average performance over the previous 5 years. A distributor can also choose to propose different baselines, supported by rationale. In either case, these will remain in place for 5 years[3]. The distributor's actual performance will be measured annually, based on a five year rolling average of their performance in order to "smooth" the varying nature of the data. This rolling average will be compared to the established baseline in order to monitor performance trends.

In order to ensure the measured distributor performance is related to conditions that are within the distributor's control, outage events related to "Major Events" will be excluded from the data used to assess performance[4].

Along with defining Major Events, the OEB will establish a process for monitoring and evaluating a distributor's performance in response to a major event.

[1] System Average Interruption Duration Index and System Average Interruption Frequency Index
[2] Baseline is an initial set of critical observations or data used for comparison
[3] In conjunction with the filing of Distribution System Plans. Please see discussions in section C.5 of this Report.
[4] The current practice of excluding "Loss of Supply" events will also continue.

The OEB will also move forward with the introduction of customer specific system reliability measures.

A.2 – Purpose of Initiative

On December 7, 2015, the Ontario Energy Board (the OEB) issued a letter announcing new initiatives related to the new objectives set out in the August 25th Report.

The first initiative will be to develop a definition of a "Major Event" that will be used to normalize reliability data that is reported to the OEB.

The second initiative will be to develop criteria and new reporting requirements that will be used to evaluate a distributor's response to a Major Event.

The third initiative will be to establish an approach to implementing "customer specific" system reliability measures.

The purpose of this OEB Report is to explore issues related to the above mentioned topics and seek stakeholder comments on initial OEB proposals.

Parties commenting on the July 15, 2014, Staff Discussion Paper on system reliability performance targets, raised an issue relating to the treatment of Major Events in evaluating reliability performance. Major events are unique events that exceed the normal design criteria of the distribution system, and are large enough to impact a significant number of customers. Events such as the 2013 ice storm have the broadest impacts on electricity customers and show up as higher values of SAIDI and SAIFI[5]. Yet these events may obscure the other key contributor to reliability performance – the state of the utility's assets. It has been suggested that in order for the OEB to effectively review a distributor's reliability performance (and ultimately the efficiency of a distributor's system plan), an analysis of a distributor's typical performance is required to allow for more accurate year to year comparisons of performance. Therefore, stakeholders commented that distributors should be allowed to report reliability data that has been adjusted to remove the impact of "Major Events".

The OEB agrees with stakeholder comments and will exclude the impact of "Major Events" from the reliability performance data that will be used to establish a distributor's SAIDI and SAIFI performance.

[5] System Average Interruption Duration Index and System Average Interruption Frequency Index respectively.

While agreeing to exclude the impact of Major Events from reliability performance data, the OEB continues to believe that the way a distributor responds to a Major Event is important. These events are by their very nature the most extreme and impactful outage events that customers experience. Given the importance of such events to reliability and to the customer experience, it is appropriate to consider how any Major Event removed from the distributor performance data should be evaluated.

The OEB has a responsibility to assure that distributors are adequately prepared to respond to Major Events and that they respond appropriately to the challenge of restoring service promptly and efficiently. To achieve this objective, the OEB will be introducing new reporting requirements for criteria that will be used to monitor and assess a distributor’s performance, including preparation prior to a Major Event; the ability restore service during/after a Major Event; and the effectiveness of a distributor’s communication to the public, including estimated restoration time during a Major Event.

In regards to implementing customer specific reliability measures, the July 2014 Staff Discussion Paper put forward a proposal to undertake a pilot project with a number of willing distributors to work towards the goal of implementing the monitoring of outages at the individual customer level. The paper also asked for input on the question of whether the OEB should set a deadline date for the implementation of customer specific reliability measures.

The majority of submissions on the Staff Discussion Paper were supportive of the OEB undertaking a pilot project related to examining the implementation of customer-specific reliability measures.

Some parties supported the introduction of a deadline for the implementation of customer specific measures. Their view is that there is no reason why Ontario distributors could not have systems in place to monitor performance at this level and a deadline would encourage distributors to move ahead with implementing the necessary requirements.

Other parties were against the introduction of a deadline. Their view is that more information is required before moving ahead. Most notably these parties submit that an analysis of the costs, and determination of whether consumers want such reporting, should be completed first.

The OEB has long recognized the need to explore reliability performance beyond the system wide level. The OEB is concerned with the extent to which specific customers may experience significantly below average reliability performance. A move towards customer specific reliability measures is essential to identifying those pockets of underserved customers. Therefore, the OEB will move forward with the introduction of customer specific system reliability measures, as soon as practical.

This Report will set out proposals for stakeholder comment on the following objectives:

- An option for defining a "Major Event";

- Options for the key activities/criteria that the OEB will use to monitor and assess the effectiveness of a distributor's response to a Major Event; and

- An approach to begin the implementation of customer specific reliability measures.

During the summer of 2015, OEB Staff reconvened the members of the System Reliability Working Group (the Working Group) that was established for previous stages of the OEB's system reliability project. Staff consulted with the Working Group to learn feedback and recommendations to achieve the above three objectives. The comments of the Working Group are set out in this paper.

The OEB is seeking stakeholder comments on how to achieve the above three objectives and specifically on the proposals set out in this paper. It is expected the results of this initiative will be amendments to the OEB's Electricity Reporting and Record Keeping Requirements.

Stakeholders are invited to provide written comments on by **January 11, 2016** in accordance with the filing instructions set out in the attached cover letter.

B. DEFINING A "MAJOR EVENT"

B.1 – Background

A review of the reliability data that distributors have reported to the OEB indicates that often there can be considerable changes in the level of performance from year to year. It is believed that some of these swings in performance are a result of the impact of significant weather events on the distribution system.

In most jurisdictions around the world, distributors exclude these types of events from their reliability statistics because storms and other Major Events are atypical and idiosyncratic, so including them can lead to a distorted perception of the distributor's underlying reliability performance. By normalizing the reliability data (i.e. – removing outages related to Major Events), distributors and regulators can review data that more closely represents typical service conditions.

It is understood that many distributors in Ontario currently apply their own normalization methodology for internal purposes[6]. Two of the more common approaches used are 1) the IEEE standard 1366[7] or 2) judging events by the effect on a certain percentage of the customer base (e.g. 10% of customers affected).

However, for the OEB to accept the exclusion of Major Events from the reported data, a definition of what constitutes a Major Event, that can be flexible but also consistently understood and applied, is required.

B.2 – Working Group Comments

One of the key suggestions by the Working Group for defining a Major Event was that a "one size fits all" approach may not be effective.

It was recommended that the OEB could provide a limited group of options or approaches to determining a Major Event that a distributor could choose from. It was suggested, that the IEEE approach could be identified as the default option, with two other options available.

[6] The OEB currently requires reporting of all outages (inclusive and exclusive of Loss of Supply events). "Major Events" are not excluded from the reported data.

[7] A statistical approach to establish the minimum impact threshold for an event to be considered a Major Event.

Alternatively, it was suggested that the OEB could set a reasonable standard and let distributors apply to claim individual events, along with an explanation for why claiming such an event as Major Event is reasonable.

Whichever option is chosen, the view was that it is important for the results to be consistent among distributors. This consistency will be of greater importance as the OEB moves to consider reliability benchmarking.

The Working Group generally supported the IEEE standard 1366 approach and suggested the IEEE approach could be linked to causes out of the distributor's control.

The Working Group expressed the view that encouraging distributors to take action to respond to these types of events if they occur again in the future is important. As such, the definition should be dynamic enough to promote the building of a system in a way that will mitigate the impact of a similar Major Events in the future.

It was suggested that the IEEE approach is dynamic because it raises the standard of what qualifies as a Major Event from year to year. If a distributor does nothing to make its system more resilient, then its' SAIDI value will increase, as will the threshold necessary to qualify for a Major Event. Since such a distributor would be unable to exclude more and more high impact events, its' reliability performance results will also decline. If a distributor does take steps to make its system more resilient, then the Major Event threshold will remain lower and more events can be excluded from the data, resulting in increased reliability performance results.

There were also discussions about the drawbacks of the IEEE approach. For example, smaller distributors may experience long periods without any outages. As a result, the data pattern of those distributors would not be considered normal and therefore using the IEEE methodology would not be appropriate. The IEEE approach also just considers the outage length on the day the event occurred. However, an event could spread over multiple days and the actual outage time each day may not trigger the major event threshold. The IEEE approach only looks at the impact of the event. It does not look at the cause and/or isolate avoidable circumstances. Therefore, an event that could have been avoided by distributor action will still trigger the Major Event threshold and be excluded from performance results.

The Working Group discussed the concept of basing the definition on the standard Canadian Electricity Association's (CEA) Cause Codes, specifically those causes which are out of the distributor's control. There were concerns raised about the Cause Codes being a qualitative measure and the fact that there can be debate about what is or is not within a distributor's control. One could make the argument that every cause is under a distributor's control or argue that almost nothing is under the distributor's control. For example, facilities impacted by foreign interference could be considered out of the distributor's control. However, such events could be within a distributor's control if enough investment was made to install safeguards to protect against such interference.

There was also discussion that basing a Major Event on weather related causes would not be effective unless there was full understanding of what constitutes abnormal weather. Without statistical evidence to justify the weather event was beyond design standards, any judgement would be qualitative.

The option of using the implementation of a distributor's emergency plan as a trigger was discussed. In this option, if emergency plan is triggered, then it is considered a Major Event. However, it was noted that Major Event instances do not always trigger implementation of the emergency plan or vice versa.

The Working Group identified some important factors that should be considered when determining a Major Event. These included:

- The duration of the event should be a factor.
- The customer-hours of outages should be a factor.
- The event should be one that disrupts the day-to-day operation of a distributor.
- When providing evidence to support a Major Event, a distributor could provide reference to its design standard and how the event exceeded those standards.

There was strong support for using the approach recently set out by the Canadian Electricity Association in their Major Event Determination Reference Guide. This approach allows distributors to choose one of three options which work best for the distributor's circumstances. These options are:

- The IEEE standard 1366
- The IEEE approach, using a two day rolling average
- The Fixed Percentage approach (i.e. 10% of customers affected)

It was suggested that those distributors who do not use the IEEE method have a requirement to provide proof/rational, at the onset of this measure, for why they do not use the IEEE method. It was felt this would not be difficult since such a distributor has likely already established the reasons for why the IEEE method is not appropriate under their circumstances.

The Working Group also sought clarity from the OEB on what outages should fall under the blanket of a Major Event. For example, a Major Event may be localized and impact only one part of a distributor's service area. All crews and resources would be focused on the affected service area. At the same time there may be "regular" outages in another part of the service area, unrelated to the Major Event, which would not receive prompt attention because of the focus on the Major Event. It was noted the IEEE standard takes all outages that happen on a Major Event Day into consideration.

The Working Group suggested that the OEB require the filing of information related to Major Events on an annual basis, not on a per occurrence basis.

It was also suggested that the OEB make it clear that the adjusted numbers exclude both Loss of Supply events and Major Events.

B.3 – OEB Research

Research has shown that the typical approaches used by distributors in North America are either the IEEE method, or the number of customers affected method. However, in Europe many distributors use an approach based on the concept of Force Majeure. The Council of European Energy Regulators (CEER) has done an analysis of the different definitions of major events by their members[8]. Some examples of how these jurisdictions defined extraordinary or Major Events are as follows:

Austria - A natural disaster takes place if a crisis situation is declared by a local authority and/or if the federal or provincial government takes measures aimed at providing financial support (e.g. catastrophe funds). In these cases it is necessary to give detailed descriptions of the natural disaster for the failure and disturbances statistics of electricity networks.

[8] CEER 4th Benchmarking Report on Quality of Electricity Supply 2008

Finland - An extraordinary event is if all the three following conditions are met 1) the interruption is out of the control of the distribution company; 2) the interruption is such that it is not reasonable for the distribution company that it could have been taken it into account in its operation; 3) the distribution company could not have avoided the interruption even when operating very carefully.

Germany - Force majeure is construed as an event brought about externally, as a result of elemental natural forces or an action by a third party; which cannot be foreseen using sensible standards of judgment; which cannot be prevented or rendered harmless with economically reasonable means even with the utmost care that could reasonably be expected in the circumstances; and which also cannot be regarded as acceptable for the operating company on the grounds of frequency.

Luxembourg - Common understanding for force majeure: All normally unforeseeable events which are external to the party invoking it, and which can’t be surmounted by the deployment of reasonable efforts to which this party is bound. There are no predefined events which would always be considered as force majeure.

The Netherlands - Incidents which occur so infrequently that it would be uneconomical to take these into account in the regulatory system and which are also beyond the control of the grid manager (e.g., powerful earthquakes, major floods, wars). This usually relates to incidents which cause exceptional and/or extensive damage to the facility, which affect a substantial number of consumers and the repairing of which takes significantly longer than usual.

B.4 – OEB Proposal

The OEB agrees with the Working Group that an effective definition of a Major Event should reference the fact that the event lasts longer than a typical outage, and disrupts the day-to-day operation of the distributor. The OEB also agrees that there should be some obligation on a distributor to determine if it can make changes to its operation that would limit the impact of similar events in the future.

It is the OEB’s view that a Major Event should be one that is on such a scale that there would be no reasonable debate that the event should or shouldn’t qualify. The identification of such events should be intuitive and obvious so that there would be no argument or judgment necessary to make a determination.

It is important to understand that the extent of the effect of a Major Event on the distribution system is not totally out of the distributor's influence. Design standards, supply redundancy strategies and overall asset age and condition of assets all play a part in mitigating these external influences. Therefore, when reviewing outage events, the OEB also believes there is a need to distinguish between events which are not out of a distributor's control but signal deteriorating infrastructure (and the need for investment) and events which overwhelm the appropriate robustness of that infrastructure (and the ability to withstand extreme events). As a result, any approach to normalizing data, must ensure that it does not allow distributors to mask inherent problems. Nor should the approach allow the assets to deteriorate, so that more and more outages fall into the Major Event category, and as such be excluded from the performance results

The OEB suggests that the European model of aligning the definition of Major Events with the concept of force majeure events would be an effective method for Ontario. This approach provides the opportunity of establishing a definition that clearly outlines the intention behind the concept of Major Events, is flexible enough of meet the different circumstances of distributors around the province, while also utilizing a commonly known legal concept.

There is also the benefit in considering the Working Group's suggestion of using the approach set out in the CEA's reference guide. The methods set out in the guide are universally accepted and familiar to distributors who likely already use one of the methods for internal purposes.

With all these factors in mind, the OEB propose the following definition:

> *A "Major Event" is defined as event that is beyond the control of the distributor and is characterized as:*
>
> 1. *unforeseeable;*
> 2. *unpredictable;*
> 3. *unpreventable; and*
> 4. *unavoidable.*

Such events disrupt normal business operation and occur so infrequently that it would be uneconomical to take them into account when designing and operating the system. Such events cause exceptional and/or extensive damage to assets, which affect a substantial number of customers, and the repairing of which takes significantly longer than usual.

"Beyond the control of the distributor" means events that are a result of natural forces or an action by a third party, including Loss of Supply events.

When assessing the threshold of a substantial number of customers affected and significantly longer restoration times than normal, distributors shall follow the recommendations set out in the Canadian Electricity Association's Major Event Determination Reference Guide. This approach recommends distributors use one of the following options whichever is appropriate to the distributor's circumstances. These options are:

- *The IEEE approach*
- *The IEEE approach, using a two day rolling average*
- *The Fixed Percentage approach (i.e. 10% of customers affected)*

To clarify some of the issues raised by the Working Group, the OEB suggests that a distributor would identify all outages that occurred during the Major Event, including those that may be unrelated to the event itself, but occurred at the same time. However, such events much also qualify as "beyond the control" of the distributor.

As discussed in the next section of the paper, when a distributor identifies a Major Event and excludes the impact of that event from their reliability performance data, the distributor will also be required to file information related to how the distributor responded to the Major Event. Among the information to be filed will be an explanation as to why the event was considered a Major Event, as well as what, if anything, the distributor plans to do to mitigate the effect of similar events in the future.

The OEB proposes that distributors continue to measure and report their performance both inclusive and exclusive of the impact of Major Events. Unadjusted information is still important for assessing a distributor's overall asset management program(s). However, for purposes of using this data on the Distributor Scorecard, the OEB proposes that the performance target be based on normalized data (including the exclusion of both Loss of Supply and Major Events).

B.5 – Questions for Stakeholder Comment

- What are the risks/benefits associated with normalizing data in this manner?
- Is the OEB's proposal for a definition of a Major Event reasonable? What are the risks/benefits of OEB's proposal?
- Is it reasonable to have distributors themselves determine which outage events are Major Events, based on the principles set out in the proposal? Or should the OEB make a determination for each event.
- Are there any other approaches to normalizing data that the OEB should consider? If so, please describe along with the risks/benefits these other options offer?
- Once a definition of a Major Event is adopted, would distributors be able to recalculate their reliability performance results for the past five years, and file this information with the Board?

C. MONITORING RESPONSE TO MAJOR EVENTS

C.1 – Background

Climate change models indicate that in the coming years, Ontario (in fact all of North America) is expected to experience an increased frequency and intensity of storm events that will likely be considered Major Events. These Major Events will have a significant impact on the operation of distribution systems across the province.

The provision of reliable and dependable electricity supply is critical to Ontario consumers. The threat on reliable supply that will arise from increased Major Events is real. In order to help minimize the impact of these events, distributors must be prepared to appropriately respond to these events. In turn, the OEB has a responsibility to assure that distributors are adequately prepared to respond to Major Events and that they respond appropriately to the challenge of restoring service promptly and efficiently.

Monitoring and evaluating distributor performance in response to Major Events is an effective way for the OEB to ensure the distribution industry is adequately prepared. The objective of this initiative is to establish a method to monitor and measure whether a distributor's response to a Major Event has been reasonable and adequate. The information gathered should highlight best practices and identify where improvements need to be implemented, resulting in more effective response and restoration efforts.

Shedding light on a distributor's performance will help ensure that they have the ability, capacity and mindset to act quickly and effectively to restore electricity supply in the face of a Major Event.

Such a reporting could review performance in relation to:

- Description of event, why it qualified as a Major Event.
- Preparedness prior to the event, including staff training.
- Accuracy of restoration time predictions.
- Efficient operational response during the event.
- Communication with customers, including IVR and web site availability.
- Use of mutual assistance agreements.
- Information on the frequency and duration of outages and number of customer's affected during event.

- What steps are being taken to be prepared for such events in the future. (i.e. – system upgrades.)

These new reporting requirements will focus on the key activities to be undertaken in response to a Major Event. The focus of this initiative will not be on the specifics of a distributor's emergency plan but rather on establishing a methodology for monitoring and evaluating the results of those plans.

The OEB will use this information to evaluate that responses to Major Events were adequate, that customer expectations were met, and to identify best practices that should be shared with the industry.

C.2 – Working Group Comments

The key recommendation from the Working Group is that any reporting requirements should focus on activities that take place in three time frames: prior to the event, during the event and after the event.

It was also suggested that the three key activities to review are: the accuracy of the estimated time of restoration (ETR); communications with customers; and details on the outage(s).

Distributor members of the Working Group expressed concern over the idea of introducing questions related to the accuracy of ETR times. These members suggested that if there is a risk that distributors will be penalized or criticized for not having accurate times, they may act differently. In that case, distributors may delay issuing an ETR until they have full confidence in the estimate, or they will give a "padded" estimate to ensure it can be met. It was reported that distributors try their best to give accurate times or else they face angry customers.

It was suggested that it is more important for the OEB to monitor whether the distributor issued an ETR, when/how quickly they issued the ETR, and how often they updated it. The view presented was that communicating and keeping the customer informed is more important than the accuracy of the first ETR. It was also suggested that quantity of ETRs issued is not an issue but rather how helpful and relevant the update was.

The Working Group proposed that questions on the effectiveness of communication could focus on how frequently and how quickly the distributor communicated with customers, including the number of calls received and how long the customer had to wait to connect with a representative. The OEB could also review the types of communication options being offered, (e.g. web site, social media, use of outage maps), as well as whether all these options were being used and working. It was suggested that it was also important to know how the distributor informed customers of their options for getting information.

Regarding the details of the outage(s), the Working Group suggested they could report details of restoration timelines. For example, they could report on how many customers were restored after 4 hours, 8 hours, 12 hours, etc.

The Working Group identified some factors that should be considered when evaluating a distributor's response to a Major Event. These included:

- Customer interactions and communications are often more important than operational response.
- Outages can limit access to modern media channels. Distributors still need to be prepared to communicate through "old school" methods.
- Identifying what actions the distributor took during the recent event that was an improvement on previous events is important.
- Reporting on "before" preparations could include confirmation on whether there were 3rd party mutual assistance agreements in place prior to the event. Also whether there has been any training on emergency procedures, including running through mock drills.
- Regarding material availability, distributors could report on whether they have arrangements in place with suppliers and neighbouring utilities to provide necessary supplies.

When reviewing a distributor's activities during the event, the Working Group suggested that it would be more effective to have distributors report on what processes they have in place and how they are prepared to respond to issues like "wires down" and damage assessment, rather than look at statistics. Questions about activities during the event could include: how many crews were in the field: how many assets were replaced, the extent of tree damage, what work schedule was utilized, etc.

The Working Group generally thought that the questions should not be too specific. Instead, it was suggested that the OEB look for distributors to provide a higher level narrative on how the distributor responded to the Major Event.

The Working Group expressed some concern regarding questions relating to contact with utility staff, since many distributors are moving away from needing to contact a live person. Rather, they are setting up web sites and IVR’s etc., to provide automated information.

If required to provide examples of what steps will be taken to be prepared for future events, distributors suggested that the focus should be on reporting on what the distributor learned from responding to the event.

There was a suggestion that since all distributors have an Emergency Plan, these plans could be filed at the same time as the Distribution System Plans. As actual events occur, performance could be tested against those plans. (E.g. – did you comply with your Emergency Response Plan? Yes or No?) There was also a suggestion that distributors could undertake transactional customer surveys to determine the customer’s opinion of how distributors responded to the event. However, it was felt that such surveys would be costly and must be standardized to make the results comparable amongst all distributors.

OEB Staff suggested any reporting requirements could be filed annually. However, the Working Group suggested the option of having the information reported soon after each event took place (e.g. a month after the event). It was suggested that distributor staff will be putting together a report for internal purposes anyways, so they could file the same report with the OEB. There was also a suggestion that distributors could file two reports. 1) a high level report that a Major Event happened (within a short time frame after the event) and then 2) a detailed report (at a later date).

The Working Group requested clarity on the question of whether the reporting would become public. The Working Group also suggested that the OEB create a standardized template for any reporting, to aide for distributors with their reporting.

C.3 – OEB Research

The impact of climate change and the issue of system resiliency is an increasingly important issue for distributors, consumers and regulators. Following the 2013 Ice Storm, PowerStream, THESL and the EDA completed assessment reports of their response to the storm.

These reports identified issues related to a distributor’s preparedness for events; the ability to handle customer call volumes; the need to improve Outage Management Systems, including increased smart meter functionality; and more effective co-ordination between work crews and internal departments.

Most importantly, the ability to communicate accurate restoration times to customers in a timely manner was identified as the biggest requirement and the biggest challenge.

Following Superstorm Sandy and other extreme weather events, the New York Public Service Commission began an initiative to develop a quantitative tool that utilities and the Commission could apply to assess utility performance in restoring electricity serviced during outages which result from a major storm. Their resulting scorecard[9] measures a distributor's performance in regards to 32 different actions/criteria that relate to preparation, operational response and communication.

C.4 – Current Regulatory Requirements

Currently the OEB's Distribution System Code includes provisions related to a distributor's emergency response plans. These are as follows:

Section 4.5.6:

> *A distributor shall develop and maintain appropriate emergency plans in accordance with the requirements of the Minister of Energy, Science and Technology and in the Market Rules, regardless of whether the distributor is a wholesale market participant. A distributor's emergency plan shall include, at a minimum, mutual assistance plans with neighbouring distributors or other measures to respond to a wide-spread emergency.*

Section 4.5.7

> *A distributor shall establish outage management policies that include the following:*
>
> - *Arrangements for on-call personnel in accordance with good utility practice.*
>
> - *Establishment and operation of a call centre or equivalent telephone service to provide consumers with available information regarding an outage.*

[9] State of New York Public Service Commission, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0140

- *Identification of the location of distribution circuits for emergency services and critical customers such as hospitals, water supply, health care facilities, and designated emergency shelters for coordination with other agencies.*

C.5 – OEB Proposal

The OEB agrees with the Working Group's suggestions that any reporting requirements should focus on activities that take place in three time frames: prior to the event, during the event and after the event. It also agrees with the suggestion that the three key activities to review are: the publication of estimated times of restoration (ETR); communications with customers; and details on the outage(s).

The OEB considers consistency in reporting this information is important in order to compare distributor responses. As a result, it believes that a series of specific questions is necessary rather than allowing each distributor to submit its own "high-level narrative".

The OEB suggests that a significant number of customers still wish to call into to speak to a live representative. However, the OEB is seeking input from stakeholders on this issue.

In regards to the timing of filing this information, the OEB proposes that requiring distributors to file reports within 60 day of the end of the event is reasonable.

The OEB proposes that distributors make the reports available to the public on their web site. The OEB is also considering posting these reports on the OEB's web site.

Considering the results of research and feedback from the Working Group, the OEB proposes that responses to the following questions are to be reported:

Prior to the Event

1. Did the distributor have any prior warning that the event would occur?
2. If so, did the distributor arrange to have extra employees on duty or on standby prior to the event beginning? If so, please give a brief description of arrangements.
3. If so, did the distributor issue any media announcements to the public warning of possible outages resulting from the pending event? If so, through what channels?
4. If so, did the distributor contact and notify those customers who rely on electricity supply for life support and/or critical facilities (e.g. – hospitals, community shelters) about possible outages resulting from the pending event? If so, through what channels?
5. Has the distributor trained its staff on the response plans for a Major Event? If so, please give a brief description of the training process.
6. Did the distributor have 3rd party mutual assistance agreements in place prior to the event? If so, who were the 3rd parties? (e.g. – other distributors, private contractors)
7. In responding to the event, did the distributor utilize assistance through these 3rd party mutual assistance agreements?

During the Event

1. Please explain why this event was considered by the distributor to be a Major Event.
2. Did other distributors in the area experience the same event?
3. What percent of distributor staff was available at the start of the event and utilized during the event?
4. Did the distributor issue any estimated times of restoration (ETR) to the public? If so, through what channels?
5. Starting from time of the first outage, at what time did the distributor issue its first ETR to the public?
6. Did the distributor issue any updated ETRs to the public? If so, how many and at what points in time were they issued?
7. What channels of communication did the distributor use to delivery ETRs to the public?
8. Did the distributor inform customers about the options for contacting the distributor to receive more details about outage/restoration efforts? If so, please describe how this was achieved.

9. How many times did the distributor send information to customers through the media? (press releases, press conferences, social media notifications) What was the general context of this information?
10. How many customers called into the distributor's phone lines during the duration of the event?
11. What percentage of these customer calls were satisfied by the distributor's IVR system?
12. What percentage of these customer calls were answered by a live representative?
13. Of the calls answered by a live representative, what percentage of the calls were the calls answered within 90 seconds.
14. Was there any point in time when the phone lines were inaccessible? If so, what percentage of the total outage time were the phone lines inaccessible?
15. Did the distributor provide information about the event on its web site? If so, how many times during the event was the web site updated?
16. Was there any point in time when the web site was inaccessible? If so, what percentage of the total outage time was the web site inaccessible?
17. How many customers were interrupted during the event? What percentage of the distributor's total customer base, did the interrupted customers represent?
18. How many hours did it take to restore 90% of the customers who were interrupted?
19. Please explain the processes the distributor followed to undertake damage assessment.

After the Event

1. Did the distributor run out of any needed equipment or materials during the event? If so, please describe the shortages.
2. What steps, if any, are being taken to be prepared for such events in the future. (i.e. – staff training, process improvements, system upgrades.)
3. What lessons did the distributor learn in responding to the event that will be useful in responding to the next Major Event?

C.5 – Questions for Stakeholder Comment

- What are the risks/benefits of introducing these new reporting requirements?
- Are the questions and reporting requirements proposed reasonable?
- Are there any questions in the proposal that do not seem relevant?
- Are there other questions that should be included in a report evaluating a distributor's response to a Major Event?
- Should the report include questions relating to calls answered by a live representative?
- Should the OEB make these reports available through its' own web site?

D. CUSTOMER SPECIFIC RELIABILITY MEASURES

D.1 – Background

The reliability measures used by the OEB, SAIDI and SAIFI, measure *system* reliability, in other words the indicators measure the *average* length of time that an *average* customer goes without power or the *average* number of times, an *average* customer experiences goes without power. These reliability measures do not show the extent to which specific customers may experience significantly below average reliability performance.

OEB has long recognized the need to explore reliability performance beyond the system wide level. The OEB is concerned with the extent to which specific customers may experience significantly below average reliability performance. A move towards customer specific reliability measures is essential to identifying those pockets of underserved customers.

As set out in the August 2015, OEB Report Electricity Distribution System Reliability Measures and Expectations, the OEB has committed to moving forward with the introduction of customer specific reliability measures, as soon as practical.
The objective of this initiative is to develop an approach to monitoring and reporting on distribution outages in a manner that identifies the outage experience at the individual customer level. This may be done by introducing reporting for Customers Experiencing Multiple Interruptions (CEMI) and/or Customers Experiencing Long Duration Interruptions (CELDI). In the alternative, stakeholders may suggest other ways that this information can be identified and reported.

Whatever the approach, in light of the objectives of the OEB's renewed regulatory framework and its focus on the customer experience, the OEB considers it important for distributors to understand the reliability performance being delivered to the individual customer.

D.2 – Working Group Comments

The key recommendation from the Working Group is to introduce customer service measures as a voluntary reporting requirement first and then transition into formal requirements over time. It was suggested that distributors be allowed to initially report to the level they are capable of (e.g. feeders to transformers to customers) and then the

OEB could set a deadline (e.g. 2025) for when all distributors must report at the customer level. It was also suggested that the OEB could launch a pilot program over a few years to review implementation issues. (e.g. – is the data accurate? Were any investment decisions made as a result of knowledge learned?)

An alternative suggestion was that as a first step the OEB could introduce a Worst Performing Feeder measure. However, there were concerns raised about such a measure including what constitutes a “feeder”? How would small utilities (with a small number of feeders) implement such a measure? Such a measure is not effective because the performance of a feeder can be poor one year and good the next without any action taken by the distributor.

The Working Group reported that the key to tracking individual customer outages is an effective Connectivity Model and keeping that model up-to date. (e.g. - this includes every time load is switched from one feeder to another.) Smart meters are not required, but distributors do need at least a GIS system to track whether a customer is affected by an outage.

Distributors noted that keeping the Connectivity Model up-to date requires established processes and staff dedicated to the task. This dedication of resources and technology will cost money. The Working Group raised the concern that early adopters will be penalized because the costs to implement such measures will lead to a higher “cost per customer” and will impact on incentive ratemaking stretch factors.

Consumer groups also raised concerns about the costs of introducing customer specific reliability measures. They recommended that the OEB undertake a study to establish the value of reliability to customers and use the results to evaluate investments in reliability improvements and monitoring. There was also a concern raised about the comparability of data if each distributor is allowed to use its own methodology to calculate results.

The Working Group requested clarity on the question of whether these measures would monitor the reliability performance delivered to a specific address/location, or to the individual customer who may move from home to home.

There was a suggestion that an implementation date of 2025 may not be aggressive enough. However, others in the group felt it was a reasonable target since many distributors would need to go through a Cost of Service application to cover the costs of new systems and technology.

Two of the Working Group members reported they already use technology to monitor customer specific reliability. When asked whether this information added any value to their operation, these distributors reported that the information was helpful especially for improved outage management and focusing rebuilding plans on the right areas. When asked if the planning knowledge would not have come to light without the technology, these distributors reaffirmed that they could do more accurate planning with the customer specific information.

D.3 – OEB Proposals

Due to the importance of implementing customer specific reliability measures, the OEB does not agree with the suggestion of introducing voluntary reporting. The OEB is also concerned that allowing distributors to report different information will not be effective for comparison purposes.

Rather the OEB agrees with the suggestion of setting a target date for the required implementation of customer specific reliability measures, in order to focus distributors on achieving the goal. The OEB proposes that the implementation date for customer specific reliability measures be set in 2018.

The OEB does agree with the WG that in order to facilitate the introduction of these measures, it would useful to undertake a pilot project with a number of willing distributors to work towards the goal of implementing the monitoring of outages at the individual customer level.

It is proposed that this project could begin by working with these distributors to review what systems and processes are readily available, or need to be available, to monitor individual customer outages and then begin testing the actual monitoring and reporting of such outages.

Some members of the WG feel that they have or can easily fulfill this aspirational goal in the short term, and expressed interest in becoming the pilot partners for this element of the initiative.

Lessons learned from this pilot project would be communicated out to all distributors so that they can begin the implementation of similar processes.

D.4 – Questions for Stakeholder Comment

- Is there any reason for not initiating a pilot project to review the implementation requirements for reporting customer level reliability data?

- What are the risks/benefits of establishing a specific implementation date of 2018 for monitoring and reporting on individual customer outages?

- Are there other options the OEB should consider to reach the goal of having customer specific reliability measures?