REVIEW

Australian Energy Market Commission

DRAFT REPORT

Distribution Reliability Measures

19 June 2014

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Draft Report

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive Summary

This draft report presents a flexible and non-binding menu of proposed distribution reliability measures that could be practically applied by the Australian Energy Regulator (AER), participating jurisdictions and others. In general, the measures and the advice contained in this draft report:

- could be used by standard setters to set distribution reliability targets;
- provide consistency in reporting on performance against their reliability targets; and
- would assist the AER and other stakeholders to compare the reliability performance of distribution businesses in the NEM.

Key distribution reliability measures

We propose harmonised definitions for the key distribution reliability measures in Box 1: that impact on customers in terms of sustained[1] and momentary interruptions.[2]

Box 1: Key distribution reliability measures

We propose definitions for the following key distribution reliability measures:

- system average interruption duration index (SAIDI), which measures the total duration of all sustained interruptions experienced by customers on average;
- system average interruption frequency index (SAIFI), which measures the average number of sustained interruptions experienced by customers;
- momentary average interruption frequency index (MAIFI), which measures the average frequency of momentary interruptions experienced by customers during the reporting period; and
- momentary average interruption frequency index event (MAIFIe), which measures the average frequency of momentary interruption events experienced by customers.

Complete definitions for these measures are provided in chapter 3 and appendix B of this draft report.

We propose that the definition of a momentary interruption and a momentary interruption event[3] is changed from less than one minute to less than three minutes. This increases the flexibility and options for distribution automation systems, which

1 Supply is not restored quickly.

2 Supply is quickly restored, in a few minutes.

3 A series of one or more momentary interruptions within quick succession.

potentially reduce their cost. The AER and the distribution businesses generally support the proposal, although SP-AusNet notes there may be transitional issues for distributors with distribution automation systems that have been purposely built to meet the one minute standard.

Further, we propose harmonised supporting definitions for planned and unplanned interruptions, customers and customer base, and interruptions.

Treatment of exclusions and major event days

It is common to remove some types of interruptions from the data set being considered when calculating distribution reliability measures. This could occur for:

- exclusions, where an interruption, or the impact of the interruption, is outside the control of the distributor; or
- major event days, where the interruptions on that day are not regarded as representative of daily operation, usually due to the weather conditions on the day.

There is currently broad agreement on the definitions and treatment of exclusions. We are proposing that exclusions be based on the current definitions used in the AER's service target performance incentive scheme (STPIS).

Similarly, there is currently broad agreement on the definitions and treatment of major event days. We are proposing that major event days be identified using the 2.5 beta method.[4] We also propose that distributors, with the agreement of the AER, may use an alternative approach, including removing catastrophic events such as major bush fires, cyclones or floods.

While we have proposed common definitions, it is up to the party that is designing a distribution reliability incentive, bench-marking or reporting scheme such as the AER to determine whether it is appropriate to apply either exclusions or major event days.

Feeder classifications

Distribution networks in the NEM supply a large range of different customers that are located in diverse geographic areas. Therefore, when measuring distribution reliability, it is common to distinguish between different parts of a distribution network by classifying the feeders on the basis of their location or loading. Classification also enables performance across distribution networks to be compared on a more realistic basis.

The AER and the most participating jurisdictions currently classify feeders as CBD, urban, short rural and long rural feeders. We are not suggesting major changes to the current definitions as the AER is considering reviewing its distribution STPIS. In

4 Institute of Electrical and Electronic Engineers Standard 1366-2012 “IEEE Guide for Electric Power Distribution Reliability Indices” updated on 31 May 2012.

addition, any material changes to the feeder classifications made in isolation may introduce significant risks to distributors which could be passed onto costumers.

We are proposing the following two incremental changes to the current classifications:

- The definition of urban feeder is currently based on actual historical loading and we propose that this be changed to a temperature adjusted maximum demand to reduce variations due to the weather in a given year.

- The definition of CBD feeder is clarified to include one or more geographic areas that are determined by the relevant participating jurisdiction.

Also, the classification of some feeders in residential areas as rural feeders is not always intuitive as the definition of urban feeder is based on a load density threshold. We discuss an alternative definition that also includes a customer density threshold. While this change is likely to lead to more intuitive feeder classifications, we are not proposing such a change in isolation as it could lead to material risks for distributors and customers.

Lowest reliability customers

The reliability experienced by some customers in a distribution network can be materially lower than many of the other customers in that network. This can be due to a number of factors including the remoteness of the customers and their relative population density. In addition, most incentive schemes reward distributors for improving average reliability, which can lead to lower reliability in areas where it would be relatively expensive to improve.

We propose that the identification of lower reliability customers should be based on the reliability being persistently lower than average. In addition, we propose system wide approaches to measuring the experience of lower reliability customers within a network compared to average outcomes.

Other reliability measures

In addition to the reliability measure on a system basis above, we discuss indices that measure reliability on a customer basis and a load basis. These measures can provide useful information if considered carefully but can be misleading and may require addition data collection systems to be established. Therefore, they are not widely used and we are not recommending their use in the NEM.

Proposed implementation plan

The proposed common definitions for distribution reliability measures have the potential to improve the consistency and transparency of the various distribution reliability incentive, reporting and bench-marking schemes used in the NEM. Thus, to derive the most benefits from the proposed common definitions, it is desirable that the measures are widely applied.

In order to facilitate the wide adoption of the proposed common definition, we propose that the definitions presented in this draft report form a non-binding guideline that could be referenced whenever an economic incentive, bench-marking or reporting scheme that adopts the definitions is being specified and applied. In addition, we consider that the definitions may need to be amended if there are improvements in the understanding of the impact of interruptions on customers or there are future technological improvements, such as innovations in distribution automation systems or the systems that monitor interruptions.

We would propose that the mechanism for implementing and maintaining a non-binding guideline for the reliability measures be set out in the National Electricity Rules (NER) and, given the proposed application of the measures, we consider that the most appropriate entity to be given the role of drafting, publishing and maintaining the guideline be the AER.

Consultation and next steps

In order to develop common definitions that could be widely adopted and applied in the NEM, we established an Advisory Stakeholder Working Group (ASWG) to assist us in considering definitions contained in this draft report. The group consisted of representatives from the AER, the Energy Networks Association (ENA) and various distribution businesses. We held two workshops with the ASWG during the preparation of this draft report. In addition to the ASWG, we consulted with the jurisdictional governments, AEMO and the jurisdictional regulatory bodies who wanted to provide input to our review. We also briefed the ENA Asset Managers for both transmission and distribution networks twice throughout the development of this draft report.

In addition, our draft report and the recommendations outlined are open for consultation. We have identified specific issues on which we are seeking comments. In addition, we welcome submissions on any other aspect of this draft report.

Our final advice will be submitted to the COAG Energy Council at the beginning of September 2014 and then published within two weeks thereafter.

Contents

1 Introduction

This document contains a set of common definitions for expressing distribution reliability targets and outcomes across the distribution networks in the National Electricity Market (NEM).

Currently the Australian Energy Regulator (AER) and each jurisdiction defines how reliability should be measured, which means it is difficult to compare the performance. Therefore, the Council of Australian Governments (COAG) Energy Council (formerly called the Standing Council on Energy and Resources) requested the Australian Energy Market Commission (AEMC or Commission) to develop common definitions for distribution reliability measures for application in the NEM. The COAG Energy Council considers this would be a useful tool to facilitate efficient investment, increase transparency and improve regulatory outcomes. The request for advice follows from work undertaken in the AEMC's review of the national framework for distribution reliability.

This review is about developing a set of common definitions for measuring the reliability of electricity distribution networks. These distribution reliability measures and the advice contained in this draft report:

- could be used by standard setters to set distribution reliability targets and other reliability measures;
- could be used by distribution businesses to provide consistency in reporting on performance against their reliability targets and measures across the NEM;
- would assist the AER and other stakeholders to compare the reliability performance of distribution businesses in the NEM;
- would assist the AER in undertaking bench-marking, which can be considered in the development of its revenue determinations for each distribution business;
- reflect the impact of the duration and frequency of supply interruptions on customers; and
- would provide a consistent set of definitions that is likely to improve customer's understanding of reliability reporting.

The distribution reliability measures contained in this draft report provide a menu of measures that can be applied by the AER, participating jurisdictions and others, as relevant for their particular application. As such, the measures proposed are flexible and non-binding.

1.1 Scope of the review

The COAG Energy Council's terms of reference for the review require the AEMC to set out:

1. the range of distribution output reliability measures which could be used to set distribution reliability targets;
2. definitions for the expression of distribution output reliability measures, including a list of the events which will be excluded from the calculation of reliability performance;
3. the classification of feeder types which will be used to set distribution reliability targets;
4. any other reliability measures which could be used in setting reliability requirements for distribution businesses; and
5. any relevant factors for the AER to have regard to in developing a methodology for undertaking an assessment of the trade-offs between reliability and cost in poorly served areas.

1.2 Background

The AEMC completed its review of the national framework for distribution reliability on 27 September 2013. The final report sets out the AEMC's recommended framework for setting and regulating distribution reliability in the NEM to promote greater efficiency, transparency, and community consultation in how reliability targets are set. To implement the framework, the AEMC recommended that work be commenced on developing common definitions for expressing distribution reliability targets.

At its meeting on 13 December 2013, the COAG Energy Council agreed to the interim measures set out in the AEMC's final report for the review of the national framework for distribution reliability. The COAG Energy Council considers the interim measures identified by the AEMC would be key steps towards the introduction of the national framework agreed in-principle by the COAG.[5] Consequently, the COAG Energy Council requested the AEMC to develop common definitions for expressing distribution reliability targets across the NEM. The AEMC's final report is due to be submitted to the COAG Energy Council by 5 September 2014.[6]

At its May 2014 meeting, the COAG Energy Council discussed a high level opt-in framework for a national approach for reliability standards to be set out in the National Electricity Rules. Ministers requested their officials to finalise a framework document for consideration at their next meeting.[7]

In the interim, the menu of distribution reliability measures contained in this draft report could still be used to provide greater consistency between the various existing

5 COAG Energy Council, Terms of Reference, received on 30 January 2014.

6 Letter granting an extension of time in relation to development of common definitions, received 26 March 2014, available on the AEMC website.

7 COAG Energy Council, Meeting Communique, Brisbane, 1 May 2014.

applications of distribution reliability measures, including the AER's service target performance incentive scheme (STPIS) and bench-marking scheme.

1.3 Advisory stakeholder working group and stakeholder consultation

The COAG Energy Council's terms of reference required the AEMC to work with the AER, the relevant electricity distribution businesses, jurisdictional regulatory bodies, and governments. Further, where appropriate, the AEMC was requested to seek feedback from relevant transmission businesses and the Australian Energy Market Operator.

We established an Advisory Stakeholder Working Group (ASWG) to assist us with the development of the policy and definitions contained in this draft report. The group consisted of AER staff representation, a representative of the Energy Networks Association (ENA) and several staff from various distribution businesses. During the preparation of this draft report the group held two workshops and considered material for the draft report. The members of the group are listed in Appendix A.

In addition to the ASWG, we consulted with the jurisdictional governments, AEMO and the jurisdictional regulatory bodies. We also briefed the ENA asset managers for both transmission and distribution networks at the beginning of the process and following the second ASWG workshop.

We are also seeking comment on this draft report from stakeholders and interested parties.

1.4 Structure of the report

This report is structured as follows:

- Chapter 2 sets out the principles and assessment framework that we are using for this review;
- Chapter 3 presents definitions for key distribution reliability measures for both sustained and momentary interruptions, as well as key supporting definitions for customers and interruptions;
- Chapter 4 outlines definitions of exclusions and major event days, and their application to reliability measures;
- Chapter 5 considers definitions for feeder classification;
- Chapter 6 discusses factors the AER should have regard to when considering the customers with the lowest reliability;
- Chapter 7 considers other potential distribution reliability measures;

- Chapter 8 provides a discussion on a proposed implementation plan for the common definitions;
- Appendix A lists the members of the ASWG; and
- Appendix B presents the set of common definitions for distribution reliability measures.

1.5 Logging a submission

Written submissions from stakeholders and interested parties in response to this draft review must be lodged with the AEMC by no later than **5pm, 18 July 2014**.

Submissions should refer to the project number "EPR0041" and be sent electronically through our online lodgement facility at www.aemc.gov.au.

All submissions received during the course of the review will be published on our website.

While we will have full regard to all submissions lodged within the specified time period, late submissions may not be afforded the same level of consideration. To ensure that we are able to fully consider all submissions, we request that stakeholders lodge their submissions by no later than the due date.

2 Principles and approach

The principles and assumptions detailed in this chapter outline the framework that we used to develop our recommendations.

2.1 Key principles

The COAG Energy Council terms of reference require that, in developing the advice, the AEMC should have regard to:

- the need to ensure that the reliability measures can be practically applied across the NEM;
- the need for consistency in setting and reporting on the distribution reliability targets across the NEM;
- the need for consistency with the AER’s STPIS for distribution; and
- the National Electricity Objective (NEO).

The following principles that promote the NEO, have guided our analysis and the formulation of the distribution reliability measures set out in this report:

- to facilitate the application of incentives that are likely to lead to economically efficient investments and operating practices, including suitability for use in the AER's STPIS;
- to reflect the impact of supply interruptions on customers in terms of the duration and frequency of interruptions, including momentary interruptions; and
- to provide consistency and transparency in the calculation of distribution reliability measures to allow meaningful reporting and bench-marking exercises to occur.

2.2 Approach

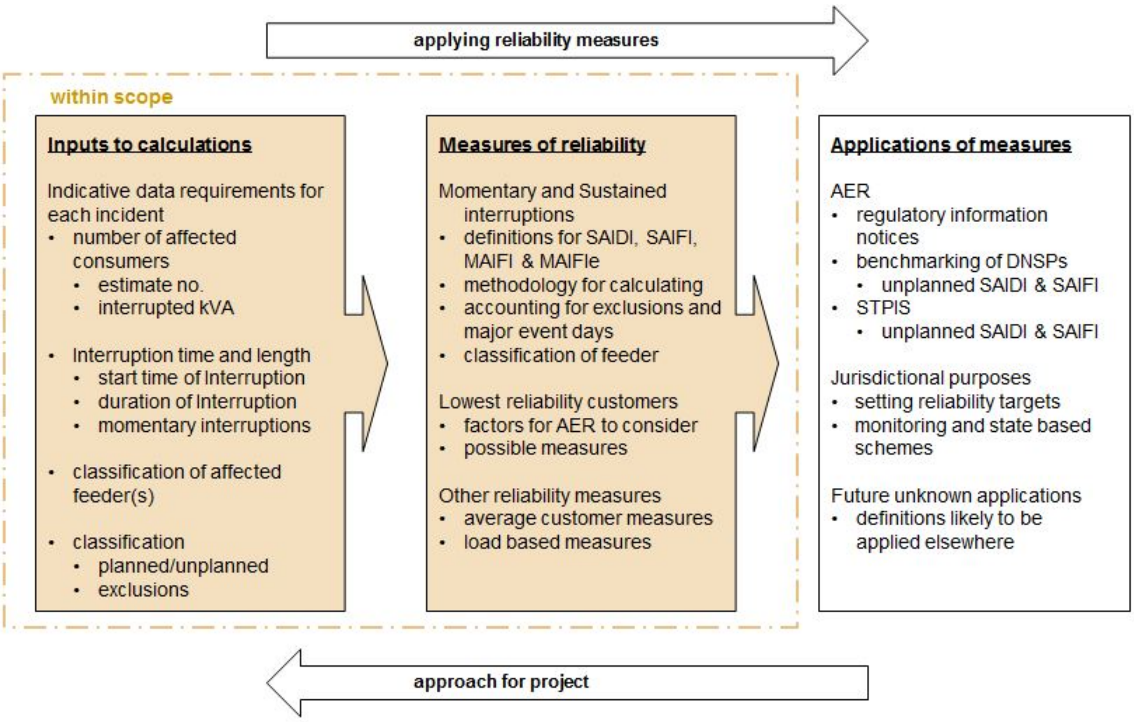
As a first step to understand the current reliability measures used in different jurisdictions for various purposes, and to seek to standardise those definitions, we collated a list of the different distribution reliability measures used in the NEM and how they are used. In particular, we considered the AER's STPIS and bench-marking requirements for distribution reliability measures, as well as the various jurisdictional reporting requirements. The ASWG assisted us with this process.

We compared the current distribution reliability measures to understand the differences between them with the aim of developing uniform definitions for all the commonly used distribution reliability measures, as well as the associated supporting definitions used when calculating the measures.

When developing the common definitions we placed particular weight on the AER definitions for its STPIS as these measures are currently used by all the distributors in the NEM. However, there are small differences between the definitions in the AER's STPIS and those developed later for its bench-marking, and we note that the AER plans to update its STPIS. We also considered the jurisdictional variations to these definitions and we had regard to the internationally accepted IEEE standard 1366 - 2012.[8]

Figure 2.1 provides an overview of the scope of this advice and the approach used to develop the common definitions of distribution reliability measures. The figure shows that the scope relates to the measures and the input data used to calculate them, but excludes proposing changes to the schemes that apply the measures. The figure also shows our approach of considering the different applications of the measures in order to identify the reliability measures and the data required to calculate them.

Figure 2.1 Overview of approach used to develop common definitions



8 Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

3 Key distribution reliability measures

The purpose of this chapter is to discuss the proposed definitions for measuring sustained and momentary interruptions. The discussion also includes the associated supporting definitions.

Distribution reliability measures are typically divided into measures of the impact of momentary and sustained interruptions to the supply of electricity to customers. Sustained interruptions usually last significantly longer than a few minutes, as restoring the supply of electricity would require one or more network components to be manually repaired or reconfigured. The impact of a sustained interruption on customers is usually significantly greater than that of a momentary interruption, making sustained interruptions of more interest in many situations.

Momentary interruptions are shorter and typically only last between a few seconds and a few minutes. This is because the cause of the interruption is only temporary and the network contains automatic systems that attempt to restore the supply. The impact of momentary interruptions on customers could be that their lights go off and return back on shortly after, possibly multiple times. This can also interfere with other electronic appliances and time-delay processes which are becoming increasingly popular with consumers looking to shift consumption to off-peak periods.

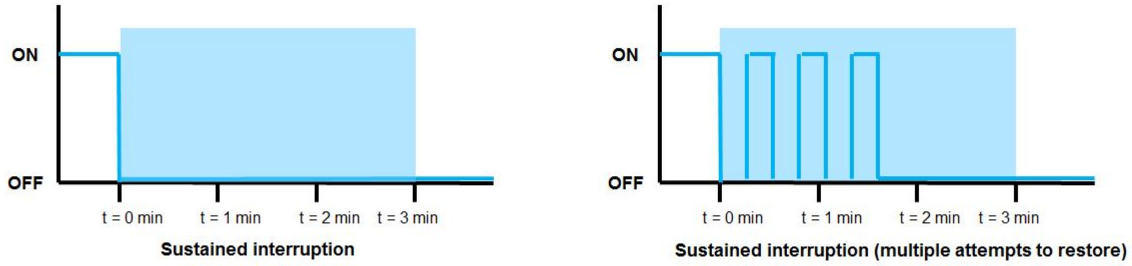
This chapter discusses two commonly applied measures for sustained interruptions, SAIDI and SAIFI, and two measures for momentary interruptions, MAIFI and MAIFIe. Our proposed definitions for these measures are general and can be applied over any time period and for any subset of interruptions (such as unplanned interruptions or feeder type etc), depending on what aspect of distribution reliability is being measured. The chapter also discusses supporting definitions associated with the general application of these measures.

There is a broad agreement on the definitions amongst the AER and jurisdictions on these measures. The key issue is the time threshold used to distinguish between momentary and sustained interruptions.

3.1 Definitions and measures for sustained interruptions

Generally speaking, a sustained interruption is an interruption of electricity supply to a customer that cannot be quickly restored. Such an interruption would be sustained until the distribution business' technicians restore supply by repairing or replacing the affected items of network equipment, or manually reconfiguring the network to restore supply to some or all affected customers. Figure 3.1 shows two examples of sustained interruptions, one where no attempt to restore supply is made and a second where several unsuccessful attempts are made.

Figure 3.1 Sustained interruptions



The most commonly used measures for sustained interruptions are SAIDI and SAIFI.

Box 3.1 Proposed definitions for distribution reliability measures for sustained interruptions[9]

SAIDI or **System Average Interruption Duration Index** in respect of a relevant period, means the sum of the durations of all the *Sustained Interruptions* (in minutes) that have occurred during the relevant period, divided by the *Customer Base*.[10]

SAIFI or **System Average Interruption Frequency Index** in respect of a relevant period, means the total number of *Sustained Interruptions* that have occurred during the relevant period, divided by the *Customer Base*.[11]

Sustained Interruption means an *Interruption* to a *Distribution Customer's* electricity supply that has a duration longer than 3 minutes, provided that the successful restoration of supply to the *Distribution Customer* is taken to be the end of the *Sustained Interruption*.

3.1.1 SAIDI - a measure of the duration of sustained interruptions

The System Average Interruption Duration Index (SAIDI) measures the total duration of all sustained interruptions (in minutes) experienced by customers on average during the relevant reporting period. Interruptions where the supply is quickly restored within a certain time-frame, usually by an auto-recloser or distribution automation systems, are excluded from the calculation and classified as momentary interruptions.

This is an important measure of customer reliability as much of the impact of supply interruptions on customers is captured by the total duration of the sustained interruptions. For this reason SAIDI is a reliability measure that is used in most distribution reliability reporting, bench-marking and incentive schemes, including the current AER's STPIS.

9 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

10 *Momentary Interruptions* are excluded from the calculation of *SAIDI*.

11 *Momentary Interruptions* are excluded from the calculation of *SAIDI*.

The definition of SAIDI is well established, by the AER and in jurisdictional instruments, and we are not proposing any material changes to its definition.

We are seeking stakeholders' views on the proposed definition in Box 3.1.

3.1.2 SAIFI - a measure of the frequency of sustained interruptions

The System Average Interruption Frequency Index (SAIFI) measures the average number of sustained interruptions experienced by customers during the reporting period. Interruptions where the supply is automatically restored by an auto-recloser or distribution automation systems within a certain time-frame are excluded from the calculation, as these are classified as momentary interruptions.

This is an important measure of customer reliability as a significant impact on customers is the number of sustained interruptions they experience. For this reason SAIFI is a reliability measure that is used in most distribution reliability reporting, bench-marking and incentive schemes, including the AER's STPIS.

The definition of SAIFI is well established, by the AER and in jurisdictional instruments, and we are not proposing any material changes to its definition.

We are seeking stakeholders' views on the proposed definition in Box 3.1.

3.1.3 Sustained interruptions - definition

The current AER documentation for its STPIS[12] and for bench-marking[13] do not have an explicit definition for a sustained interruption, rather these documents exclude momentary interruptions which are defined as less than one minute. Therefore, the implied definition of a sustained interruption is an interruption with a duration of greater than one minute.

We are proposing to explicitly define a sustained interruption. For the reasons given in section 3.2, we are proposing the duration of a momentary interruption as being defined as three minutes or less. Accordingly, we are proposing the duration of a sustained interruption be defined as greater than three minutes.

During the restoration process for a sustained interruption it is not uncommon for customers to experience one or more temporary restorations of electricity supply prior to supply being successfully restored. Accordingly, we propose that the duration of a single sustained interruption for the purposes of calculating SAIDI and SAIFI be taken to begin at the start of the sustained interruption and end when electricity supply has been successfully restored.

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12 AER, *Electricity distribution network service providers - Service target performance incentive scheme*, November 2009.

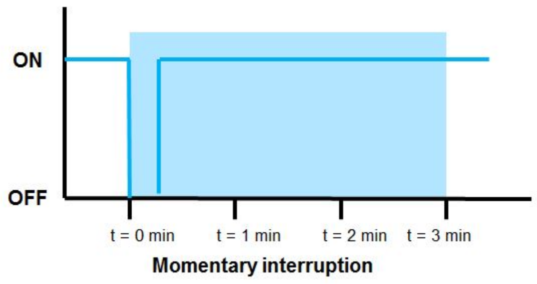
13 AER, Economic bench marking RIN for distribution network service providers - Instructions and Definitions, November 2013.

We are seeking stakeholders' views on the proposed definition in Box 3.1.

3.2 Definitions and measures for momentary interruptions

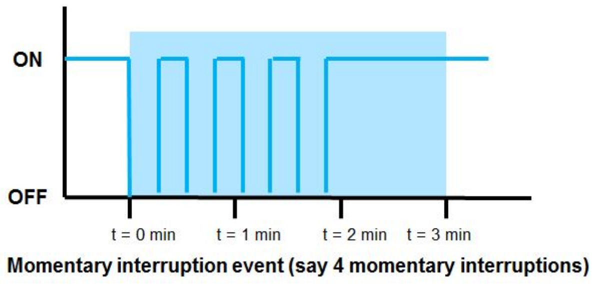
Generally, a momentary interruption is a brief loss of electricity supply to a customer caused by the opening and closing of a circuit breaker or similar device. This would typically happen following a successful operation of an auto-recloser or distribution automation systems. Figure 3.2 shows an example of momentary interruption, where a successful attempt to restore supply has been made.

Figure 3.2 Momentary interruption



It is not uncommon for an auto-recloser or distribution automation system to require more than one attempt to restore supply to affected customers. If this is the case, the affected customers experience a series of momentary interruptions before supply is restored (if supply isn't restored quickly then it is a sustained interruption). A series of one or more such momentary interruptions is defined as a momentary interruption event. Figure 3.3 shows an example of a momentary interruption event where supply is successfully restored after several attempts have been made.

Figure 3.3 Momentary interruption event



The most commonly used measures for momentary interruptions are MAIFI and MAIFIe. These measures reflect the average number of momentary interruptions and momentary interruption events experienced by customers, respectively.

Box 3.2: Proposed definitions for distribution reliability measures for momentary interruptions[14]

MAIFI or **Momentary Average Interruption Frequency Index** in respect of a relevant period, means the total number of *Momentary Interruptions* that have occurred during the relevant period, divided by the *Customer Base*, provided that *Momentary Interruptions* that occur within the first three minutes of a *Sustained Interruption* are excluded from the calculation.

MAIFIe or **Momentary Average Interruption Frequency Index event** in respect of a relevant period, means the total number of *Momentary Interruption Events* that have occurred during the relevant period divided by the *Customer Base* for the relevant period, provided that *Momentary Interruptions* that occur within the first three minutes of a *Sustained Interruption* are excluded from the calculation.

Momentary Interruption means an *Interruption* to a *Distribution Customer's* electricity supply with a duration of 3 minutes or less, provided that the end of each *Momentary Interruption* is taken to be when electricity supply is temporarily restored or, in the absence of a temporary restoration of supply, when supply is successfully restored.

Momentary Interruption Event means one or more *Momentary Interruptions* that occur within a continued duration of 3 minutes or less, provided that the successful restoration of electricity supply after any number of *Momentary Interruptions* is taken to be the end of the *Momentary Interruption Event*.

3.2.1 MAIFI - a measure of the frequency of momentary interruptions

The momentary average interruption frequency index (MAIFI) measures the average frequency of momentary interruptions experienced by customers during the reporting period. Where one or more unsuccessful attempts to restore supply occur, which results in a sustained interruption, the associated momentary interruptions are not included in the calculation of MAIFI.

We are not proposing any material change to the current definition of MAIFI other than defining a momentary interruption as an interruption with a duration of three minutes or less, compared to the current one minute. The proposed change to the definition of a momentary interruption is discussed in section 3.2.3.

We are seeking stakeholders' views on the proposed definition in Box 3.2.

14 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

3.2.2 MAIFIe - a measure of the frequency of momentary interruption events

The momentary average interruption frequency index event (MAIFIe) measures the average frequency of momentary interruption events experienced by customers during the reporting period. Where one or more unsuccessful attempts to restore supply occur, which results in a sustained interruption, the associated momentary interruption event is not included in the calculation of MAIFIe.

We are not proposing any material change to the current definition of MAIFIe other than defining a momentary interruption as event as having a duration of three minutes or less. The proposed change to the definition of a momentary interruption event is discussed in section 3.2.3.

We are seeking stakeholders' views on the proposed definition in Box 3.2.

3.2.3 Momentary interruptions and momentary interruption events - definitions

The current AER documentation for its STPIS[15] and bench-marking[16] define a momentary interruption as being less than one minute. The current definition based on one minute would generally allow sufficient time to attempt to restore the supply of electricity with several auto-recloser operations. However, not all distribution automation systems could operate this quickly due to the more complex operations they are able to attempt in order to restore the supply.

If the allowed duration of momentary interruptions and momentary interruption events is extended to three minutes, there would be an improved alignment between the response capability of many distribution automation systems and the performance measures (ie to operate within the time-frame defined for a momentary interruption). For the majority of networks, where distribution automation systems have not yet been deployed in scale, this would provide the potential to reduce the cost of implementing distribution automation systems to operate within the momentary interruption threshold. In conjunction with favourable STPIS incentives the increased adoption of distribution automation systems could lead to economic investment to improve reliability performance.

We note that the definition for sustained interruptions is greater than three minutes in the UK and the current IEEE standard[17] defines a sustained interruption as being greater than five minutes. In the case of the UK, OFGEM changed its definition of a sustained interruption from one minute to three minutes in 2000 to better align with

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15 AER, *Electricity distribution network service providers - Service target performance incentive scheme*, November 2009.

16 AER, Economic bench marking RIN for distribution network service providers - Instructions and Definitions, November 2013.

17 Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

European standards and to provide an incentive for distribution automation systems that could speed up restoration of supply for some customers.[18]

Therefore, we are proposing that the definitions of momentary interruption and momentary interruption event be changed to a duration that is three minutes or less. As discussed in section 3.1.3, we are also proposing to align the definition of a sustained interruption to greater than three minutes.

There is potential for a revised STPIS, aligned to the proposed changes to service measure definitions, to financially impact distributors who have responded to the existing incentives and already implemented distribution automation schemes. Should the proposed change to the definitions be implemented, it will be necessary for the AER to address the uncertainty and the potentially negative financial implications for these distributors when setting transitional mechanisms and price reviews. These distributors include SP AusNet, which has implemented distributed automation systems across its network, as well as Powercor and Citipower that have more recently commenced a distributed automation system roll-out.

Box 3.3: Request for stakeholder views on definitions for momentary interruption and momentary interruption event

We are seeking stakeholders' views on the proposed definitions for momentary interruption and momentary interruption event in Box 3.2. In particular, we are seeking stakeholders' views on how changing the duration of a momentary interruption from 1 minute to 3 minutes could:

- impact consumers in terms of potentially longer momentary interruptions and in terms of a likely reduction in sustained interruptions; and
- materially increase the range of distribution automation system alternatives that could be cost effectively implemented, thus increasing the number of systems deployed.

3.2.4 The use of MAIFI and MAIFIe in bench-marking and economic incentive schemes

MAIFI counts all momentary interruptions, unless supply is not restored. If incentive schemes include a penalty on MAIFI then the distributors under the scheme would have an incentive to minimise the number of momentary interruptions. This could manifest as a disincentive for the distributors to invest in auto-reclosers and distribution automation systems. This may not be in the interests of the affected customers as more interruptions would thus become sustained interruptions if the distributor has a disincentive to risk more momentary interruptions by attempting to restore the supply.

18 OFGEM, *Information and incentives project - definition of input and output measures*, document 60702A/0020 V1.0, October 2000.

On the other hand, MAIFIe counts momentary interruption events, rather than the individual momentary interruptions that make up the event. If incentive schemes include a penalty on MAIFIe, rather than MAIFI, then this would not operate as a disincentive for the distributors under the scheme to invest in auto-reclosers and distribution automation systems. This is because the actual number of momentary interruptions that occur within a momentary interruption event are not counted when calculating MAIFIe, so distributors are not penalised for attempting to restore supply more than once during a momentary interruption event. Rather, if the relative penalty on MAIFIe is less than SAIDI and SAIFI, the distributors would have an incentive to invest in auto-reclosers and distribution automation systems in order to try to restore supply quickly and avoid the penalties associated with sustained interruptions.

It appears likely that the impact on most customers of multiple momentary interruptions within a momentary interruption event is not materially more than the impact of a single momentary interruption. That is, most of the impact of a series of momentary interruptions, within a momentary interruption event, would be due to the first interruption. For example, the first momentary interruption may cause the need for clocks, computers and other applicants to be reset, with additional momentary interruptions within a few minutes unlikely to cause further impact on affected customers.

Therefore, we consider that, for the purposes of incentive schemes on distributors, MAIFIe is a more preferable measure of momentary interruptions than MAIFI. This is because MAIFIe is a better measure of the impact of the interruptions on customers and because MAIFI can act as a disincentive for distributors to try to restore supply automatically.

Box 3.4: Request for stakeholder views on the impact of momentary interruptions and momentary interruption events

We are seeking stakeholders' views on whether the impact on customers of multiple momentary interruptions, within a single momentary interruption event, is likely to be materially greater than a single momentary interruption.

3.3 Other supporting definitions

This section provides definitions that are necessary to clarify the application of the measures defined in sections 3.1 and 3.2 under different circumstances. In particular, definitions for planned and unplanned interruptions, customers and customer base, and interruptions are discussed.

Currently there are small differences between the various supporting definitions used in the NEM. We are proposing changes to these definitions in order to standardise them.

Box 3.5: Proposed supporting definitions[19]

Planned Interruption means an *Interruption* resulting from a *Distribution Network Service Provider's* intentional interruption of electricity supply to a *Customer's* premise where the *Customer* has been provided with prior notification of the *Interruption* in accordance with all applicable laws and regulations.

Unplanned Interruption means an *Interruption* that is not a *Planned Interruption*.

Customer means an end user of electricity who purchases electricity *supplied* through a *distribution system* to a *connection point*.

Distribution Customer means a *connection point* between a *distribution network* and *Customer* that has been assigned a *NMI*, including energised and de-energised *connection points* but excluding *unmetered connection points*.

Customer Base in respect of a relevant period, means:

- the number of *Distribution Customers* as at the start of the relevant period; plus
- the number of *Distribution Customers* as at the end of the relevant period,

divided by two.[20]

Interruption means any loss of electricity supply to *Distribution Customers* associated with an *outage* of any part of the *network*, including *outages* affecting a single *Customer's* premises but excluding *disconnections* caused by a *retailer* or a fault in electrical equipment owned by a *Customer*, provided that:

- the start of an *Interruption* is taken to be when the *Interruption* is initially automatically recorded by equipment such as *SCADA* or, where such equipment does not exist, at the time of the first *Customer* call reporting that there has been an *outage* in the *network*; and
- the end of an *Interruption* is taken to be when the *Interruption* is automatically recorded as ending by equipment such as *SCADA* or, where such equipment does not exist, the time when electricity supply is restored to affected *Distribution Customers*.[21]

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19 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

20 Indices are calculated on whichever reporting period is required.

21 The number of affected *Customers* during an *Interruption* may need to be estimated

3.3.1 Total, planned and unplanned interruptions

The distribution reliability measures in sections 3.1 and 3.2 can be applied on a total, planned or unplanned basis. The decision to consider only planned or unplanned interruptions will depend on the specific applications of the measures.

In all cases interruptions have an impact on customers. The nature of this impact may depend on whether the interruption is planned or unplanned. In the case of a planned interruption, the affected customers may be able to make alternative arrangements to reduce the impact of the supply interruption. However, in the case of an unplanned interruption, the affected customers get little or no notice that the supply will be interrupted so the impact will be greater.

Planned interruptions are required from time to time by the distributors in order to perform maintenance. Maintenance of the components of distribution networks is required to prevent damage of the equipment. During periods of maintenance, one or more components of the network are out of service which can cause a planned interruption to the supply of some customers and can reduce the level of redundancy in the network. While the impact of planned interruptions is generally less than that for unplanned interruptions, multiple planned interruptions could have a significant impact on customers.

Unplanned interruptions occur when the outage occurs with little or notice. This can occur when a component of the network fails or is damaged with no notice at all, or when an emergency outage is required when the distributor considers a component failure is imminent. Unplanned outages can also occur if the distributor is required to disconnect some customers for an emergency such as a transmission network failure or a civil emergency like a bush-fire.

The current definitions of planned and unplanned interruptions used by the AER and other regulators generally distinguish on the basis of whether sufficient notice has been given to the affected customers. We agree that interruptions should be considered as unplanned unless customers have been given sufficient notice, as defined by the requirements for notices for interruptions that apply in the relevant participating jurisdiction.

We note that under the National Energy Customer Framework (NECF), customers must be given at least four business days' notice before the date of the interruption. In participating jurisdictions that have not adopted the NECF the notice requirements vary. We consider that it is not necessary to require a common notice period of four business days, as per NECF, as this would be unlikely to create a significant change to the resulting reliability measures and would create inconsistency within the participating jurisdictions that require a different notice period requirement.

We are seeking stakeholders' views on the proposed definitions for planning interruption and unplanned interruption in Box 3.5.

3.3.2 Customer

It is important to define which customers should be included, and hence which should be excluded, when calculating the distribution reliability measures. Currently slightly different definitions of a customer have been applied for different purposes and across different participating jurisdictions.

We propose that customers should be defined in terms of metered national metering identifiers (NMIs), where a NMI is a unique identifier assigned to the metering installation at a metered connection point.

Consideration was given to whether customers at a de-energised connection point should be excluded from the definition of a customer, as is the case under some current definitions. We consider excluding such customers would introduce unnecessary administrative burden, especially as very few connection points would be de-energised for the reporting period, typically an entire year.

Under the current AER's STPIS, and the majority of other applications, unmetered public lighting is not considered to be customer for the purposes of calculating reliability measures, with the option of including or excluding other unmetered connection points. Our proposed definition excludes all unmetered connection points from being considered as customers for the purposes of calculating reliability measures, as this would be simpler to apply. We note that incentive scheme do not generally target unmetered supplies as these have different contractual arrangements.

Adopting the proposed customer definition would mean that the current inconsistencies in the definitions across the NEM would be removed going forward. However, as the number of unmetered connection points is relatively small, this would be unlikely to cause a material discontinuity from historical reliability measures.

We are seeking stakeholders' views on the proposed definitions for planning interruption and unplanned interruption in Box 3.5.

3.3.3 Customer base

The customer base is the total number of customers being considered when calculating the reliability measures above.

To account for the fact that the total number of customers may vary throughout the reporting period, the total number of customers included in the calculation of reliability measures should be the average of the number at the beginning and the end of the period being considered. This is the standard approach currently applied. The alternative of taking this average would be to keep a record of the total customers at the time of each individual interruption, which would be burdensome.

We are seeking stakeholders' views on the proposed definitions for planning interruption and unplanned interruption in Box 3.5.

3.3.4 Interruption

An interruption is the loss of supply to one or more customers. The current definitions for an interruption vary in terms of what events are included and excluded.

We propose that, for the purposes of calculating reliability measures, interruptions should exclude loss of supply due to disconnection by a retailer (eg for non-payment or safety reasons), and disconnection due to fault within the affected customer's electrical installation. This is because disconnection of a customer for either of these reasons would be unrelated to the reliability of the power system.

We recognise that there may need to be some degree of estimate when determining the number of customers that are affected by an interruption. An example of this would be for single phase faults where the distributor may not have accurate records of which customers are on which phase. The need for estimation has been reflected in the proposed definition.

We also note that defining an interruption in terms of a loss of supply excludes from the definition poor power quality events such as the presence of harmonics, voltage surges, voltage sags, voltage flicker and brownouts. This is generally consistent with current approaches. Such poor power quality issues are taken into account separately to the calculation of the distribution reliability measures considered in this report. We note that some distributors currently treat brownouts as a loss of supply, particularly in the case of the operation of a high voltage (HV) fuse.

When calculating SAIDI, it is also necessary to know the duration of each interruption. The AER's STPIS defines the start of an interruption as when it is recorded by equipment such as SCADA[22] or, where such equipment does not exist, at the time of the first customer call relating to the network outage.[23] The proposed definition is based on this approach and includes a similar definition for the end of the interruption.

We are seeking stakeholders' views on the proposed definitions for planning interruption and unplanned interruption in Box 3.5.

22 System control and data acquisition is a system that provides remote monitoring of the network as well as some level of remote control of the network.

23 AER, *Electricity distribution network service providers - Service target performance incentive scheme*, November 2009.

4 Treatment of exclusions and major event days

The purpose of this chapter is to discuss the treatment of exclusions and major event days when calculating distribution reliability measures, where:

- exclusions are where an interruption, or the impact of the interruption, is outside the control of the distributor; and
- major event days are days where the interruptions on that day are not regarded as representative of daily operation, usually due to the weather conditions on the day.

It is common to remove some types of interruptions from the set of reliability data being considered when calculating distribution reliability measures. This will be because these interruptions are not relevant to the aspect of reliability being measured, or the purpose for which it is being measured. The data excluded will depend on the objective of the associated reporting, bench-marking or incentive scheme.

Examples of interruptions that may be removed from the reliability data are interruptions that are not caused by the distributor or where the distributor has no impact on the outcome. Such interruptions are referred to as exclusions and are discussed in section 4.1. Exclusions may be excluded when the focus is on the performance of the distributor on those areas it is considered as being able to control.

The other commonly removed interruptions are those that occur on major event days where the interruptions and the associated distributor's response are regarded as untypical of the normal operation of the distributor's network. A small number of major events would occur in a typical year and would usually be associated with events such as thunder and wind storms, hot weather or bushfires. The identification and treatment of major event days is discussed in section 4.2.

The existing reliability measures used on the definitions and treatment of exclusions and major event days are broadly consistent. The key issues are the load interruptions associated with directions from emergency services and the impact of catastrophic events on the process for identifying major event days.

4.1 Exclusions - events outside the control of the distributor

When distribution reliability is considered (eg reported) purely from the perspective of the service experienced by customers then all interruptions should be included, irrespective of the cause. However, when bench-marking the performance of distributors or applying an incentive scheme, it is common to remove events that are beyond the control of the distributor from the calculation of the reliability measures. Such events include lack of generation or a failure in the transmission network where the distributor can neither act to reduce the probability of such an event occurring nor manage the restoration of supply.

However, exclusion events do not normally include events such as lightning, bushfires or car accidents where the distributor does not necessarily have any control over the cause of the event but is expected to manage the restoration of supply to customers and could plan its network to mitigate the probability and impact of such events.

Box 4.1: Proposed definitions for exclusions[24]

Exclusions - *Interruptions* that result from the following circumstances may be excluded from the calculation of *SAIDI*, *SAIFI*, *MAIFI* and *MAIFIe*:

1. *Load shedding* due to a *generation* shortfall.
2. Automatic *load shedding* due to the operation of under-frequency relays following the occurrence of a *power system* under-frequency condition.
3. *Load shedding* at the direction of *AEMO* or a *System Operator*.
4. *Load* interruptions caused by a failure of the shared *transmission network*.
5. *Load* interruptions caused by a failure of *transmission connection assets* except where the *interruptions* were due to inadequate planning of *transmission network connections points* and the *Distribution Network Service Provider* is responsible for the planning of *transmission network connection points*.
6. *Load* interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under *jurisdictional electricity legislation* and *national electricity legislation* applying to a *Distribution Network Service Provider*.
7. *Load* interruptions caused by, or extended by, a direction from state or federal emergency services.

The AER's current STPIS includes six events that may be excluded when calculating the reliability measures. These are:

1. load shedding due to a generation shortfall;
2. automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;
3. load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator;
4. load interruptions caused by a failure of the shared transmission network;
5. load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission

24 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

connections and the DNSP is responsible for transmission connection planning; and

6. load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.[25]

The same exclusions are also used by the AER for bench-marking.[26] We agree that the distributor has no control over any of the exclusions listed above, except to the extent that it may be required to perform the load shedding in some cases such as a direction from AEMO in accordance with pre-defined jurisdictional arrangements.

Exclusion (6) above makes reference to jurisdictional electricity legislation, which is defined in the National Electricity Law to be:

> "**jurisdictional electricity legislation** means an Act of a participating jurisdiction (other than national electricity legislation), or any instrument made or issued under or for the purposes of that Act, that regulates the generation, transmission, distribution, supply or sale of electricity in that jurisdiction;"

We consider that this definition may be too narrow to capture all interruptions caused by emergency services related powers under jurisdictional legislation. For example, a distributor may be directed to interrupt supply to a group of customers, or may be denied access to undertake repairs, pursuant to legislation which may or may not directly relate to the regulation of electricity. Such events are recognised in some of the jurisdictional reliability measures.

To clarify the definitions, we propose that an additional exclusion for load interruptions caused by, or extended by, a direction from emergency services[27] be added to the numbered list of exclusions above. We note that this is exclusion is consistent with the AER's transmission STPIS.[28]

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25 Section 3.3(a) of AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.

26 Page 49 of the AER, *Economic bench marking RIN for distribution network service providers - Instructions and Definitions*, November 2013.

27 We note that the need for an emergency services officer to issue a direction to a distribution business may depend on the materials used for the feeder's construction and the state of repair. For example, it is more likely that a feeder with wooden poles, compared to concrete and steel, would need to be de-energised in a bushfire. In such circumstances it could be argued that the planning and operating practices (ie the choice of wooden poles) influenced the need to be directed, and that such a direction should not be regarded as an exclusion.

28 Pages 22, 24 and 25 of the AER, *Final electricity transmission network service providers - service target performance incentive scheme*, December 2012.

Box 4.2: Request for stakeholder views on proposed list of exclusions

We are seeking stakeholders' views on whether the proposed list of exclusions accurately reflects the types of interruptions that could be excluded from the calculation of distribution reliability measures for the purposes of bench-marking or economic incentive schemes.

4.2 Major event days

4.2.1 Treatment of major event days

Generally, major event days are days on which the distribution network experienced stresses beyond that normally expected (such as during severe weather). It is common to remove major event days, as well as the exclusions discussed above, from the database of interruptions when considering the underlying performance of a distribution network. This is because major event days can be considered as outliers when compared to the normal day-to-day interruptions that occur within a distribution network.

Box 4.3: Proposed definitions for major event days and catastrophic events[29]

Major Event Day - *Interruptions* that occur on a Major Event Day may be excluded from the calculation of SAIDI, SAIFI, MAIFI and MAIFIe. *Major events day* has the meaning given in the *IEEE Guide*, provided that:

- for the purposes of applying an economic incentive scheme, the regulator may apply a different multiple of log standard deviation than the 2.5 multiple used in the statistical method set out in section 3.5 of the *IEEE Guide* should such multiple be determined by the regulator to more accurately reflect the normal operation of the *distribution network*; and
- *Catastrophic events* may be excluded from the statistical method used to classify *Major Event Days*.

Catastrophic event means a large scale event (such as a cyclone, flood or bushfire) that is identified by:

- applying a 4.15 multiple to the log standard deviation used in the statistical method set out in section 3.5 of the *IEEE Guide*; or
- such other statistical method determined by the regulator to more accurately identify large scale events.

29 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

IEEE Guide means the 'IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Std 1366-2012' published by the Institute of Electrical and Electronic Engineers on 31 May 2012.

The AER's current STPIS includes the ability for major event days to be excluded from the calculation of the distribution reliability measures for incentive purposes.[30] The AER also allows interruptions to be removed from the reliability data for major event days as part of its bench-marking.[31]

It may not be appropriate to remove interruptions on major event days from the reliability data when considering reporting on the reliability of the service experienced by customers or for distribution planning purposes.

Even though the interruptions that occur on major event days may be removed from the network's database of interruptions, they should not be ignored. Rather, these interruptions should be separately analysed and reported given that they have had a significant impact on the reliability experienced by many customers.

4.2.2 Identifying major event days - the IEEE 2.5 beta method

For its current STPIS and its bench-marking, the AER requires that the 2.5 beta method is used to identify major event days.[32] This method is defined in the IEEE Standard 1366-2012[33] and is applied in many countries.

Under the IEEE method, a major event day is defined as a day where the daily SAIDI[34] is greater than the threshold, T_{MED}. The T_{MED} value is calculated at the end of each reporting period (typically one year) for use during the next reporting period, as follows:

1. collect values of daily SAIDI (usually the unplanned SAIDI) for five sequential years, ending on the last day of the last complete reporting period;

2. remove days that did not have any interruptions from the data set;

3. take the natural logarithm (ln) of each daily SAIDI value in the data set;

4. find α (Alpha) and β (Beta), the average and standard deviation of the logarithms of the data set respectively;

30 Section 3.3(a) of AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.

31 Page 36 of the AER, *Economic bench-marking RIN for distribution network service providers - Instructions and Definitions*, November 2013.

32 Section 3.3(a) of AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.

33 Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

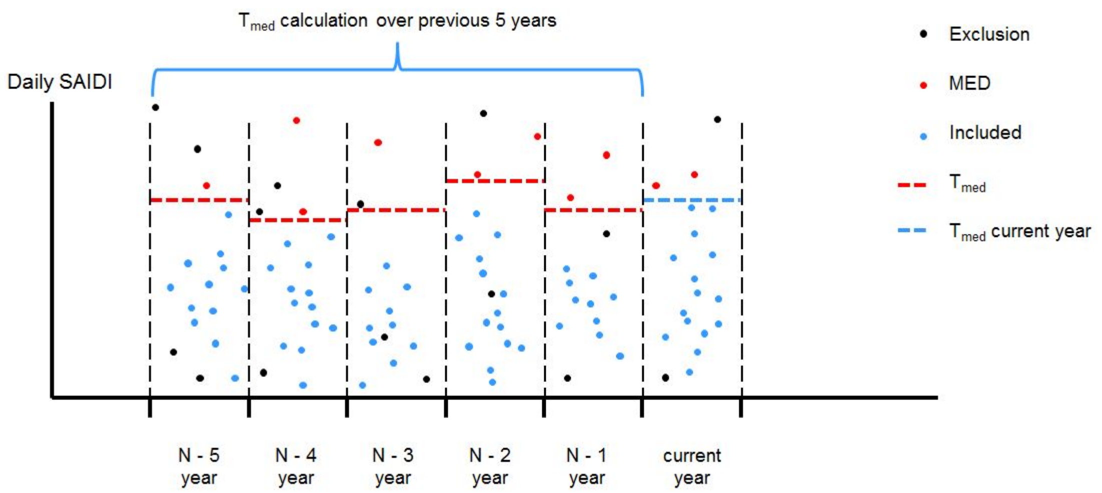
34 The value of SAIDI calculated for the interruptions on a given day.

5. compute the major event day threshold, $T_{MED} = e^{(\alpha+2.5\beta)}$; and

6. any day with a daily SAIDI greater than T_{MED} that occurs during the subsequent reporting period is classified as a major event day.

Figure 4.1 describes the process for removing exclusions and identifying major event days. The black dots represent exclusions and are removed from the data set for the past five years and for the current year being considered. The red dots represent the major event days and the blue dots represent the days where the daily SAIDI is non-zero but less than T_{med}. T_{med} for the current year is calculated using all the daily SAIDI values (blue and red dots) from the previous five years[35] and used to identify the major event days in the current year. The interruptions associated with the blue dots in the current year can then be used to calculate the reliability measures of interest (eg SAIDI, SAIFI, MAIFI and MAIFIe etc).

Figure 4.1 The 2.5 beta method for identifying major event days



The operation of the 2.5 beta method relies on the natural logarithm (ln) of each daily SAIDI values being approximately Gaussian (normal) distributed. If this is not the case then the AER's STPIS allows the distributor to propose an alternative transformation to be applied to the daily SAIDI values which results in a more normally distributed data set.[36] The AER's current STPIS also allows a distributor, with the AER's agreement, to modify the 2.5 beta method to provide for a higher major event day threshold, for example a threshold of 2.8 beta,[37] where a higher major event day threshold may better identify those days where the distribution network experienced stresses beyond that normally expected.

35 Five years of historical data is used to balance the need for a long data series to accurately estimate T_{med} while acknowledging that the distribution system and its operating practices are evolving over time. The IEEE standard 1366-2012 discusses this in section B.8.

36 Appendix D of AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.

37 Appendix D of AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009.

We propose that the 2.5 beta method described by the IEEE, and referred in the AER's STPIS, be used for bench marking and be the default method to be used when applying an economic incentive scheme to the distributor.

We also propose that the distributor, with the agreement of the relevant regulator (such as the AER), can amend the 2.5 beta method if the resulting distribution reliability measures better reflect normal operation of that specific distribution network.

We note that the calculation of T_{med} is based on all interruptions in the past five years, with the possible exceptions of the exclusions (discussed in section 4.1) and catastrophic events (discussed in section 4.2.3). That is, while interruptions that occur on major event days are removed from the calculation of the reliability measures for that year, these interruptions are included in the calculation of T_{med} for the next five years. This means that distributors, that are subject to incentive schemes that remove interruptions on major event days, still have an incentive to reduce interruptions on major event days in order to reduce T_{med} in future years.

Box 4.4: Request for stakeholder views on proposed definition for major event days

We are seeking stakeholders' views whether the 2.5 beta method described in IEEE standard 1366 - 2012 is the appropriate default method for identifying major event days.

4.2.3 Catastrophic events

The 2.5 beta method for identifying major event days relies on the assumption that the natural logarithm of the daily SAIDI values is approximately Gaussian distributed. While this is generally the case, the IEEE notes that some events can be very severe and can distort the 2.5 beta method for identifying major event days.[38] Examples of such extreme events could be cyclones, floods or bushfires. The presence of a catastrophic event in the previous five years will result in a higher T_{med} threshold. This has the effect of including some interruptions from days that may be regarded as major event days, thus distorting the calculation of the distribution reliability measures for the five years following the catastrophic event. We understand that the incidence of catastrophic events has affected the application of the AER's STPIS scheme in South Australia. This happened because the five years prior to the current regulatory period did not include any catastrophic events but several such events have occurred since.

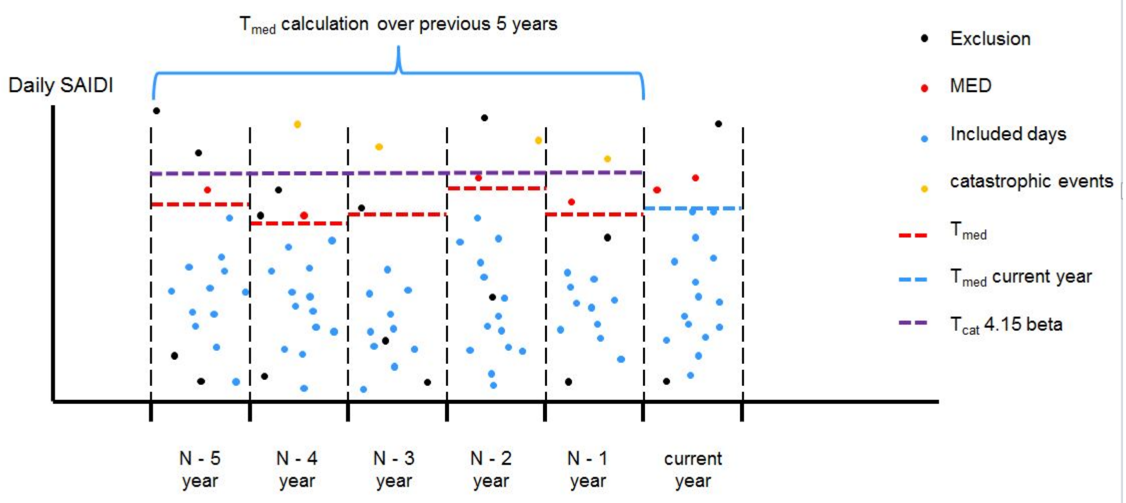
The IEEE standard considers that it is necessary to identify catastrophic events from the previous five years and remove them prior to the application of the 2.5 beta method. The IEEE reported that several methods of identifying catastrophic events

38 Section 5.3 of the *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

were developed but no definitive method was identified.[39] However, we understand that the 4.15 beta method has proven to work in many instances.[40] The difficulty in finding a definitive method for identifying catastrophic events is that such events are relatively rare so there is limited statistical data available to prove the validity of any potential methods.

Figure 4.2 describes the application of the 4.15 beta method. The black dots represent exclusions and are removed from the data set for the past five years and for the current year being considered. The threshold for excluding catastrophic events T_{cat} is calculated from the daily SAIDI values from the previous five years. Any event that exceeds this threshold is excluded from the data set of interruptions prior to calculating the T_{med} in the usual manner. The remaining interruptions can then be used to calculate the reliability measures of interest (eg SAIDI, SAIFI, MAIFI and MAIFIe etc).

Figure 4.2 Including catastrophic events in the identification of major event days



We propose that the 4.15 beta described by the IEEE could be used to identify catastrophic events and that the interruptions associated with these events could be excluded from the data set prior to the application of the 2.5 beta method. We also propose that the distributor can, with the agreement of the relevant regulator, propose an alternative method when it is applying an incentive scheme.

As catastrophic events can last for several days, it is also necessary to define the end of such events. We propose that a catastrophic event ends when the distributor declares the end of the emergency condition, as defined by the relevant emergency management plan.

39 Section 5.3 of the *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012. We also discussed identifying catastrophic days with an IEEE representative.

40 IEEE presentation, *Uses of the IEEE 1366 and catastrophic days*, John McDaniel, Vice Chair - Distribution Reliability WG, April 2012, available at http://www.eei.org/meetings/Meeting_Documents/2012Apr-TDM-McDaniel.pdf

The IEEE is unclear whether a catastrophic event is excluded from the calculation of T_{med}. There are two possible methods to exclude catastrophic events. The first approach is to exclude any consecutive major event days when at least one of the days exceeds the catastrophic day threshold T_{cat}. The second approach is to only exclude the days (defined from midnight to midnight) that exceed T_{cat}.

Box 4.5: Request for stakeholder views on proposed definition for catastrophic events

We are seeking stakeholders' views on whether:

- catastrophic events should be excluded from the distributor's data set of interruptions; and
- the 4.15 beta method is the appropriate default method for identifying catastrophic events.

4.3 Application of exclusions and major event days

Section 4.1 above provides a discussion of possible exclusions that could be used when calculating distribution reliability measures. Similarly, section 4.2 above provides a method for identifying major event days, which can also be excluded from calculating distribution reliability measures. The purpose of this section is to provide some high level guidance on the use of exclusions and major event days in different applications of distribution reliability measures.

The views expressed in this section are high level principles that may be relevant to entities that apply distribution reliability measures. However, ultimately the decision whether to remove any exclusions or major event days from the distributor's data-set of interruptions depends on the relevant regulatory body or distributor using the measures. In particular, this decision depends on overall objective of the application of the distribution reliability measures, and on the philosophy of the regulatory body or distributor designing the associated economic incentive, bench-marking or reporting scheme, or operating strategy.

4.3.1 Economic incentive schemes

The distribution networks in the NEM are subject to the AER's STPIS and are also often subject to a jurisdictional service standard. The aim of such schemes is to provide incentives on the distributors to maintain and improve service performance, and to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for the distributor. To implement an incentive scheme it is necessary to measure the reliability provided by the distributor subject to the scheme.

When considering the reliability provided by a distributor it is usual to consider the performance of the network under normal operating conditions. This means that, when implementing an incentive scheme, it would be common to remove interruptions that are associated with exclusions (as defined in section 4.1) and major event days. Interruptions associated with exclusions would be removed because these events cannot be influenced by the distributor. Similarly, the interruptions on major event days are generally regarded as outliers and not representative of the underlying performance of the distributor.

Planned outages are not currently included in economic incentive schemes. This is because the guaranteed service level (GSL) payments for not meeting the minimum notice period are expected to compensate the affected customers.

4.3.2 Reporting and bench-marking

It would be usual to allow exclusions and to remove major event days when considering distribution reliability from the perspective of a distributor's performance, which is similar to the case of distribution network incentive schemes. This is because exclusions and major event days involve operating conditions that are either out of the distributor's control or beyond their normal operating conditions.

When considering distribution reliability from the customer's perspective, the operation of exclusions and major event days may be irrelevant. The majority of customers are likely to be indifferent as to the cause of an interruption, that is, whether it is due to the actions of the distributor or outside of its control. Rather most customers would primarily be concerned with the impact of the interruption on themselves. Therefore, a reporting or bench-marking scheme that is designed to measure the impact on customers is unlikely to allow exclusions or major event days.

Planned outages would typically be removed or reported separately as they may have a different impact on customers.

4.3.3 Setting reliability targets and network planning

Network planning is primarily concerned with meeting the customers' overall reliability expectation, as expressed in the targets contained in the associated reliability standards. Therefore, as customers are affected by all interruptions, the objective of network planning should be the reliability the networks delivered under all conditions, including those that are likely to arise on major event days.

For consistency with the network planning objective above, the reliability standards for network planning should also consider all potential interruptions that could arise from within the distribution network, including those that are likely to occur on major event days and during planned outages.

Reliability targets associated with economic incentive schemes should only take into account interruptions that would occur under normal operating conditions if the incentive scheme allows major events to be excluded from the set of interruptions used to calculate the distribution reliability measures.

While the distribution planner should primarily be concerned with the impact on customers, it may not always be appropriate for network planners to consider events which they do not have any influence over, such as the exclusions listed in section 4.1.

It is unlikely that a network planner would be requested to plan to meet their reliability targets taking into account events associated with the exclusions above. Rather the entities that can influence the exclusions should have systems or infrastructure in place to manage the exclusions. An exception to this would be the joint planning undertaken between transmission and distribution networks, where the distributor is involved with the transmission system planning decisions that may affect the performance of its distribution network.

5 Feeder classification

The purpose of this Chapter is to discuss the classification of feeders when considering distribution reliability measures.

Many of the distribution networks in the NEM supply a large range of different customers that are located in diverse geographic areas. Therefore, when measuring distribution reliability, it is common to distinguish between different parts of a distribution network by classifying the feeders[41] on the basis of their location or customer density. Classification also enables performance across distribution networks to be more closely compared.

The AER and the many of the participating jurisdictions currently classify feeders into the CBD, urban, short rural and long rural classifications. The key issues are that the classification of some urban and rural feeders changes from year to year due to seasonal variations, and the classification of some feeders as urban or rural is not always intuitive.

Box 5.1: Proposed definitions for feeder classifications[42]

CBD feeder means a *feeder* in one or more geographic areas that have been determined by the relevant participating jurisdiction as supplying electricity to predominantly commercial, high-rise buildings, supplied by a predominantly underground *distribution network* containing significant interconnection and redundancy when compared to urban areas.

urban feeder is a *feeder* which is not a *CBD feeder* and has a weather normalised maximum demand over the feeder route length greater than 0.3 MVA/km.

short rural feeder means a *feeder* with a total feeder route length less than 200 km, which is not a *CBD feeder* or *urban feeder*.

long rural feeder means a *feeder* with a total feeder route length greater than 200 km, which is not a *CBD feeder* or *urban feeder*.

Alternative definition for urban feeder

urban feeder is a feeder which is not a **CBD feeder** and either:

- has a weather normalised maximum demand over the feeder route length greater than 0.3 MVA/km; or
- has a customer density of greater than X customers per route km of feeder length.[43]

41 A feeder is a power line, including underground cables, that is part of a distribution network.

42 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

This alternative definition would improve the intuitiveness of the definition of urban feeder, however, we are not proposing that this change is made in isolation to a review of the associated reliability targets and incentive schemes.

5.1 Introduction

5.1.1 The need for feeder classifications

Distribution networks supply customers in a large range of different circumstances from the centre of capital cities to the end of a long rural feeder. The reliability that is expected at the centre of a large capital city is much higher than that in a remote rural area. Also, the capital costs per customer of the feeders that supply different geographic areas can vary greatly. In addition, the types of customers and the uses they have for electricity varies significantly between parts of the network.

To account for the range of different customers' circumstances and expectations, it is common to classify either the customers or the feeders that supply them.

5.1.2 Current classification system

The current classification used by the AER in its STPIS and for bench-marking was originally developed by the Essential Services Commission in Victoria. It was used for the state based incentive scheme and for reporting distribution reliability. This classification system was adopted by the AER when it commenced regulation of the distribution networks.

The current classification system used by the AER divides feeders into four categories namely:

- CBD feeder - a feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
- urban feeder - a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km.
- short rural feeder - a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km.
- long rural feeder - a feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km.

This classification system was initially proposed by the Steering Committee on National Regulatory Reporting Requirements in 2002, which reported that "the

43 An appropriate value of X is yet to be determined in consultation with stakeholders.

categorisation of feeders was not widely supported but there was no common theme to alternative proposals."[44] This classification system is adopted in the majority of the participating jurisdictions in the NEM. The exceptions are:

- South Australia, which used to use its own geographic feeder classification system, but recently aligned itself with the AER classifications for incentive purposes. ESCOSA will now require SA Power Networks to report using both the AER classification and its historical system;[45]
- Tasmania, which classifies on a customer or community basis.

These participating jurisdictions adopted classification categories because they considered that the feeder classifications above lead to classifications of feeders in their distribution networks that were not always intuitive for customers.

5.2 Issues with the current feeder classifications and proposed changes

We have considered some of the issues of the current feeder classifications. The issues that were identified with the current classifications are that:

1. the classification of some urban and rural feeders changes from year to year due to seasonal variations;
2. the classification of some feeders as urban or rural is not always intuitive for customers;
3. the concept of CBD means different things to different parties;
4. the classifications are coarse; and
5. some feeders can supply a variety of customers.

In the case of the first three issues we have proposed incremental changes to the relevant definitions to address these issues. While in item 2 we are proposing a potential change to the definition of urban feeder to improve its intuitiveness, we are not proposing that this change is made in isolation of a review of the associated reliability targets and incentive schemes. Changing this definition is expected to re-classify a material number of rural feeders as urban which is likely to raise the calculated SAIDI and SAIFI for both classifications.

We are not proposing any changes to address the last two issues as these would require more substantial changes that would be likely to have wider impacts. We understand that the AER is considering reviewing various aspects of its STPIS, and this

44 Page 6, Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, March 2002, page 6

45 Essential Services Commission of South Australia, *SA Power Networks Jurisdictional service standards for the 2015-2020 regulatory period*, May 2014

is likely to include further consideration of feeder classifications. This may mean that the reliability measures set out in this report may need to be subsequently amended to address such changes.

5.2.1 Volatility between the urban and rural feeder classifications

The classification of urban feeders is on the basis of load density (ie a load density greater than 0.3 MVA/km). Currently the actual historical loading is used to classify urban feeders, and hence rural feeders. This has meant that some feeders have been reclassified from rural to urban following a particularly hot summer, or from urban to rural following a particularly mild summer. This volatility in the classification of these feeders introduces noise in associated economic incentive, bench-marking and reporting schemes. In addition, it can introduce risks to distributors when different reliability targets apply to these classifications, which is usually the case.

We understand that some distributors that have experienced this volatility in the classification of some of their feeders have agreed with the AER to retain the original classification for incentive purposes, when it is believed that it would be a temporary change in the classification. However, we also understand that not all distributors have adopted this approach. Therefore, we consider that addressing this issue would promote greater consistency between the businesses.

We are proposing that the feeder load density should be calculated from the temperature normalised maximum demand, rather than the actual historical loading. We consider this would reduce the volatility of the classification of some rural and urban feeders.

We understand that this proposed change is unlikely to introduce a significant burden on the distributors as they calculate the temperature normalised maximum demand for their major feeders as part of their annual planning. In addition, we consider that this proposed change would not introduce a material discontinuity in the historical reliability data used for bench-marking as the change mainly removes noise in the classification process, rather than introducing a systemic bias.

Box 5.2: Request for stakeholder views on using temperature normalised maximum demand

We are seeking stakeholders' views on whether the proposal to use the temperature normalised maximum demand:

- would be likely to reduce uncertainty and risk for the distributors; and
- introduces any adverse impacts.

5.2.2 The classification of some feeders is not always intuitive

Currently the only criterion for classifying urban feeders is on the basis of load density. This has not always led to intuitive classifications of feeders in some residential areas.

These residential areas appear to be "urban", as there is a reasonably high housing density, but may be supplied by feeders that are classified as "rural" if the average load density is below the 0.3 MVA/km threshold. This misalignment between customers' expectations and feeder classification has contributed to the desire of some participating jurisdictions to classify their feeders on the basis of geographic area or community.

The extent of this misalignment could be reduced if the urban classification included a second criterion based on customer density. That is, a feeder could be classified as urban if either the load density or the customer density is above its respective threshold. This would mean that customers that are in a suburban area would be likely to be classified as urban as they would be surrounded by a relatively high density of customers. The current load density criterion should be maintained as this would capture industrial areas where the customer density may be lower but the load density would be relatively high.

We consider that this incremental change could reduce the driver for some participating jurisdictions to report on a geographic area or community as the classifications would better align to the circumstances of many customers. That is, including both a load and customer density criterion in the urban classification would capture both feeders with high load density, such as industrial areas, and feeders with high customer density, such as residential areas. In any case, these participating jurisdictions could continue to require reporting on their existing feeder classifications, as well as the alternative definition.

This alternative urban feeder classification is also likely to be more consistent over time if the load density changes due to the penetration of solar PVs, new appliances and, potentially, electric vehicles. That is, changing consumption patterns by some customers over-time could have an impact on the load density but, under the alternative definition, this would not change the classification if the customer density were sufficiently high.

We note that the distributors have been providing reliability data to the AER for a number of years and a change to the classification could introduce a material discontinuity in the historical reliability data. This discontinuity could be removed if the distributors recast their historical data sets with the new classifications. We understand from discussions with the distributors that they do not consider this to be a large burden.

We also note that the feeder classifications are currently used by the AER, and potentially other entities, for other purposes not directly related to distribution reliability. An example of this would be the AER's expenditure models. However, we understand from the AER that it is not particularly concerned with maintaining consistency with the feeder classifications used for all its regulatory activities, and may modify these classifications for other purposes.

The alternative definition includes a value of customer density (no. of customers per km) to be applied as a threshold between urban and rural areas. However, analysis by the ENA has identified that there is no single value of customer density where there is an apparent division into urban and rural feeders, or where there is a clear step change in reliability performance.

The AEMC, in conjunction with the ENA, considered the option of converting the current load density threshold into an equivalent customer density of 100 customers per km. This could be achieved by dividing the load density threshold of 300kVA/km by an assumed median demand of 3 kVA per customer.

Analysis by a number of distributors has shown that a significant number of feeders and customers could be switched from short-rural to urban if the alternative urban feeder classification were to be adopted with a threshold of 100 customers per km. This could result in material changes to the calculated reliability performance measures (SAIDI and SAIFI) for both urban and short-rural feeders. Thus, if the change is made in isolation, it could introduce a financial risk to affected distributors who would be perceived as delivering lower reliability, or to customers if the distributors recovered the additional costs to restore the previous reliability performance, as measured. These risks could be mitigated if the associated reliability targets and incentive schemes were re-assessed if the alternative definitions were adopted. We anticipate that the distributors will provide further analysis in submissions to this draft report.

Box 5.3: Request for stakeholder views on alternative criterion for urban feeder classification

We are seeking stakeholders' views on whether the proposed additional criterion for classifying urban feeders:

- would provide a more intuitive feeder classification in lightly load suburban areas; and
- how it could be implemented given the potential impacts on affected distributors.

5.2.3 Different interpretations of CBD

The concept of CBD means different things to different parties. This has meant that the CBD feeder classification has been interpreted differently and it might not be clear to stakeholders reading reports on reliability.

We are proposing that the relevant participating jurisdiction determine which geographic area or areas should be classified as CBD based on the existing criterion of predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy. This clarification of the definition is consistent with current practice and allows for future flexibility as the characteristics of cities and towns change.

Box 5.4: Request for stakeholder views on amendment of the CBD definition

We are seeking stakeholders' views whether the proposed definition of CBD feeder is appropriate, in particularly, whether a participating jurisdiction should be able to define more than one CBD.

5.2.4 Feeders that supply a variety of customers

It is common for feeders to start at a suburban substation and supply customers in the surrounding suburban area, but then continue into the surrounding country. The average loading on such a feeder could be low because of the low load density supplied by a large part of the feeder, even though the first part of the feeder is supplying suburban customers. This issue arises because rural feeders can be quite long and can supply a diverse range of customers.

While this issue cannot be easily addressed by the current feeder classifications, one approach would be to apply the classifications to feeder sections rather than feeders. This would add to the administrative burden of calculating distribution reliability measures but would, in some instances, produce more meaningful measures.

We consider that classifying on the basis of feeder section may have some merit and there could be a transition to classifying on the basis of feeder sections over time. The distribution reliability measures and associated feeder classifications proposed in this report could be applied on either a feeder or feeder section basis.

5.2.5 Coarseness of the classification system

The current classification system is coarse in that it only has four classifications that span most of the extremes of the Australian continent, and the full range of customer reliability expectations. This can cause material steps in the reliability targets from one classification to another. This means that there may be significant costs to a distributor if a number of its feeders are reclassified from one category to another, which can happen when there are large developments (eg residential) on the outskirts of an urban area. Note that classifying by feeder sections instead of feeder would reduce this problem.

We consider that these risks of that arise from the coarse feeders classifications cannot be addressed by incremental changes to the current definitions, and therefore, should be left to a more comprehensive review of the operation of the AER's STPIS.

6 Lowest reliability customers

The purpose of this chapter is to discuss what factors we consider the AER should have regard to when developing a method for assessing the trade-offs between reliability and cost in those areas that experience lower levels of reliability of electricity supply.

The reliability experienced by some customers in a distribution network can be materially lower than that experienced by many of the other customers in that network. This can be due to a number of factors including the remoteness of the customers and their relative population density. It is necessary to develop some relevant measures of this variation in customer reliability outcomes if its impact is being assessed.

6.1 Areas with poorer reliability

6.1.1 Reasons for areas with poorer reliability

Some areas in a distributor's network will be more expensive to supply reliably. This may be due to lower customer numbers, where the cost per customer of the assets supplying them is higher than for the majority of other customers supplied by the distributor. This is common in remote parts of a distributor's network where a long feeder is required to supply a few customers, as the cost of a feeder is generally proportional to its length, and the cost of building redundancy into the network would be high. In addition, some areas may have lower reliability due to the historical configuration of the network.

6.1.2 Effect of economic incentive schemes

The majority of economic incentive schemes, including the AER's current STPIS, reward distributors for improving average customer reliability. This is achieved by placing incentives on distribution reliability measures such as SAIDI, SAIFI, MAIFI or MAIFIe, where these measures are calculated as an average across either a single feeder classification or across the whole network.

When designed appropriately, such an incentive scheme encourages cost effective investment in projects that improve the average reliability of the associated distributor's network. However, such an incentive scheme also rewards investments that improve the reliability to a large number of customers at a low cost. The impact of such incentive schemes is to discourage investments that are more expensive and benefit a smaller number of customers. This can lead to pockets of customers that experience reliability that is significantly worse than a typical or average customer. These customers with lower reliability would generally not be impacted by improvements in average reliability.

6.2 Principles for considering lowest reliability customers

We consider that the following principles are important in identifying the customers with the lowest reliability.

Box 6.1: Principles for considering lowest reliability customers

We are proposing that the following principles should be considered when developing a method for assessing the areas with the lowest reliability customers:

1. The approach used should be able to be applied consistently across the jurisdictions and distributors.

2. The focus should be on customer experiences of reliability, rather than on feeder reliability.

3. The approach needs to measure the experience of the lowest reliability customers compared to that of the average customers, on feeders of the same classifications.

4. The approach needs to take into account that reliability outcomes may vary from year to year.

6.2.1 Consistency between distributors and jurisdictions

The factors that need to be considered when identifying the lowest reliability customers should be able to be applied in a consistent manner across all jurisdictions and distribution networks.

6.2.2 Focus should be on customer experience

The focus of distribution reliability measures is usually on a feeder basis. This is appropriate for the aggregate measurements required for existing incentive, bench-marking and reporting schemes. However, this may not be appropriate for identifying those pockets of customers that experience lower reliability. The reliability experienced by different customers on a given feeder can vary if the feeder is sub-divided into sections.

The sub-division of feeders into feeder sections improves the reliability of customers near the substation that supplies the feeder, but may not improve the reliability experienced by customers near the remote end of the feeder. This is because when a fault occurs part way along the feeder, it can be split so that the customers near the associated substation may not be interrupted or, if they are, their supply can be restored relatively quickly, especially if the feeder has an automation scheme operating. The customers near the remote end of the feeder may not be restored for some time while a repair is made.

This means that the reliability measures that are based on feeder reliability measures, such SAIDI or SAIFI by feeder, will not always effectively identify the individual customers that experience the lowest reliability. A better proxy for the experience of the customers with the lowest reliability would be the SAIDI or SAIFI values generated on an individual feeder section basis.

In addition, customers are generally more adversely affected by unplanned interruptions, compared to planned interruptions. Therefore, the measures of customer reliability should be based on unplanned SAIDI or SAIFI.

6.2.3 The need to measure the experience of the lowest reliability customers compared to the average customers

The reliability experienced by the lowest reliability customers is only of concern to the extent that it is significantly different to that of typical or average customers. That is, if the reliability experienced within a network is relatively uniform then no customers appear to be materially disadvantaged. If, however, some customers experience reliability that is much lower than others it may be desirable to examine the reasons why and, where appropriate, address these reasons.

Therefore, it is necessary to develop measures of the extent to which the reliability experienced by the lowest reliability customers differs from the average experience of customers supplied by feeders of the same classification. As an alternative, the experience of the lowest reliability customers can be compared to the relevant reliability target, rather than the average of the actual experiences of customers.

6.2.4 Reliability outcomes may vary from year to year

The interruptions experienced by customers are somewhat random in nature. This is because the root cause of some interruptions, like lightning, bushfires and faults caused by animals, occur randomly. Consequently, it is possible that the customers that experience the lowest reliability in one year may not have such low reliability in the next year.

Therefore, the process to identify the lowest reliability customers needs to consider whether the low reliability is due to an unfortunate set of outcomes in a given year, or whether there is a systemic issue with the reliability experienced by certain customers. This can be achieved by considering customers that have low reliability for several consecutive years, or by applying a moving average over several years to the customers' annual reliability.

6.3 Possible measures for considering lowest reliability customers

The reliability measures that are appropriate when considering lowest reliability customers depend on the objective of applying the measures. We have considered two broad approaches that:

1. identify the actual customers with lowest reliability; and

2. apply network wide measures of lowest reliability outcomes.

6.3.1 Identifying the actual customers (by feeder section) with the poorest reliability

One approach for considering the lowest reliability outcomes is to identify the actual feeder sections that supply the customers with the lowest reliability. Having identified these feeder sections, this information could be used in the distributor's planning process to consider projects that would improve the reliability for these customers. An incentive scheme could be placed on the distributor that encourages it to consider the projects that would benefit those customers identified under this process, while recognising the costs involved.

If such an approach were developed then the number of lowest performing feeder sections would need to be relatively small to avoid excessive burden on the distributor. Therefore, we suggest that a lowest reliability customer would be identified when:

1. the SAIDI for the feeder section is greater than a specific threshold (for example four times the average SAIDI or the target SAIDI value);

2. the SAIDI for the feeder section is in the worst 5% of feeder section SAIDI values; and

3. the feeder section has been identified as having the lowest reliability, using both the first two criterion, for a number of consecutive years (for example three years).

The development of a specific process to identify the lowest reliability feeders or feeder sections would need to review historical reliability data to ensure that the appropriate level of burden is placed on the distributor. For example, the thresholds in criteria 1 and 2 above should be set at levels that focus the distributor on an appropriate number of lower reliability customers. In addition, an alternative to applying the approach above to feeder sections, the measures could be applied to individual customers as the necessary reporting systems are already in place as part of the guaranteed service level (GSL) scheme.

6.3.2 Using network wide measures of lowest reliability outcomes

Another possible approach is to measure the range of different reliability outcomes experienced within the network, particularly the outcomes for the lowest reliability customers. Under this approach, the object isn't to identify the actual feeders experiencing the lowest reliability, but to have a measure of the variation of reliability outcomes across the network.

Measures that may be appropriate for measuring the reliability outcomes for the lowest reliability customers compared to the average are:

1. the percentage of feeders or feeder sections with a SAIDI greater than a threshold (for example four times the average SAIDI);[46]

2. the ratio of SAIDI for the lowest reliability customers (say 5% of customers) to the average SAIDI for all feeders or feeder sections;

3. CEMIn - the percentage of customers experiencing n or more sustained interruptions (per year);[47] or

4. the average SAIDI value for the customers that experience more than n interruptions (per year).

In principle each of these measures could be incorporated into an economic incentive, bench-marking or reporting scheme that would encourage the distributor to analyse why some of its customers receive lower reliability and to consider projects to improve their reliability, where the returns under the incentive scheme outweigh costs of the projects.

The CEMIn measure may be useful in identifying the extent that some customers are experiencing multiple interruptions in a year. Some drawbacks of this measure are that it does not consider the duration of the interruptions being experienced by the lowest reliability customers, and it may not reduce even if customers experience fewer interruptions if they are still experiencing more than n interruptions.[48]

The development of a specific process to measure the range of different reliability outcomes experienced in a network would require a review of historical reliability data in order to determine appropriate thresholds required for the selected measures above.

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46 This approach is equivalent to the CELID measure defined in the IEEE Standard 1366 - 2012.

47 CEMIn is defined in the IEEE Standard 1366 - 2012.

48 Page 59 and 60 of Richard E. Brown, Electric power distribution reliability, second edition, CRC Press, 2009.

7 Other distribution reliability measures

The purpose of this Chapter is to identify other distribution reliability measures which could be used in setting reliability requirements for distribution reliability.

We consider that the reliability measures discussed in previous chapters of this draft report are generally suitable to be applied in the context of Australia, depending on the specific application.

The COAG Energy Council has also requested advice on any other reliability measures which could be used in setting reliability requirements for distribution businesses. We have examined other measures that have been used internationally, in particular, those in the IEEE standard.[49]

The distribution reliability measures presented in this chapter may be suitable in some specific circumstances but each has short-comings and we are not proposing to recommend that these measures be used in the NEM.[50] These short-comings are discussed below.

7.1 Customer based distribution reliability measures

The SAIDI and SAIFI measures discussed in this draft report are widely used, both in Australia and internationally. These measures consider the duration and frequency of sustained interruptions on a system basis (either the distribution network as a whole or a sub-set of the network, for example urban feeders). There are three similar measures that express the impact of sustained interruptions on a customer basis. For the reasons below we are not proposing to recommend the use of these customer based distribution reliability measures.

Box 7.1: Customer based distribution reliability measures that may be used[51]

CAIDI or **Customer Average Interruption Duration Index** in respect of a relevant period, means the sum of the durations of all *Sustained Interruptions* (in minutes) that have occurred during the relevant period, divided by the total number of *Sustained Interruptions* (ie *SAIDI* divided by *SAIFI*).[52]

CAIFI or **Customer Average Interruption Frequency Index** in respect of a relevant period, means the average frequency of *Sustained Interruptions* that have

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49 Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

50 As we are not proposing these definitions we have not put them in a consistent form to those in chapter 3.

51 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

52 *CAIDI* excludes *momentary interruptions*.

occurred during the relevant period for those *Customers* experiencing *Sustained Interruptions*.

CTAIDI or **Customer Total Average Interruption Duration Index** in respect of a relevant period, means the total time during the relevant period that average *Customers* who actually experienced an *Interruption* were without power. This is similar to *CAIDI*, except that those *Customers* with multiple *Interruptions* are counted only once.

7.1.1 Customer Average Interruption Duration Index (CAIDI)

Like SAIDI and SAIFI, CAIDI is another measure of the impact of sustained interruptions. In particular, it measures the average time to restore supply following an interruption. CAIDI is calculated as the sum of the duration of each sustained interruption (in minutes) that occurs in the period of interest, divided by the total number of sustained interruptions that occurred in the period. By definition, CAIDI can also be calculated as the ratio of SAIDI divided by SAIFI.[53]

While CAIDI provides a measure of average time to restore supply following an interruption, it can provide a misleading impression of the reliability experienced by customers in that network. For example, if the distributor invests in a series of projects that reduce the frequency of short interruptions, then both the SAIDI and SAIFI values would reduce but the SAIFI would reduce more. While both reductions in SAIDI and SAIFI indicate improved reliability experienced by customers, the CAIDI would rise, indicating increased unreliability.

7.1.2 Customer Average Interruption Frequency Index (CAIFI)

CAIFI, like SAIFI, is a measure of the average frequency of sustained interruptions. However, instead of being averaged over all customers, CAIFI is the average frequency of sustained interruptions for those customers experiencing sustained interruptions.[54]

CAIFI may provide useful information on customer reliability under some circumstances, but it can also provide a misleading impression under other circumstances. For example, if the distributor invests in projects that tend to improve the reliability of customers that have a low number of sustained interruptions, but leave the customers with multiple sustained interruptions unaffected, CAIFI would increase even though overall reliability as measured by SAIDI and SAIFI would have improved. This is because the total number of customers experiencing sustained interruptions would have reduced but the number of customers experiencing multiple sustained interruptions would not have reduced. That is, while both reductions in

53 Section 3.2.3 of the Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

54 Section 3.2.5 of the Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

SAIDI and SAIFI indicate improved reliability experienced by customers, the CAIFI would rise, indicating increased unreliability.

7.1.3 Customer Total Average Interruption Duration Index (CTAIDI)

CTAIDI, like SAIDI, is a measure of the average duration of sustained interruptions. However, instead of being averaged over all customers, CTAIDI is the average duration of sustained interruptions for those customers experiencing sustained interruptions.[55]

CTAIDI may provide useful information on customer reliability under some circumstances but, like CAIDI and CAIFI, it can also provide a misleading impression if the distributor invests in projects that tend to improve the reliability of customers that have a low number of sustained interruptions.

7.2 Load based distribution reliability measures

The generally applied SAIDI and SAIFI measures indicate the average duration and frequency of the sustained interruptions by weighting the impact of the interruptions by the number of customers affected. This approach implicitly gives equal weight to all customers, irrespective of their size.

An alternative approach to measuring the average duration and frequency of the sustained interruptions involves weighting the impact of the interruptions by the size of customers affected. That is, instead of scaling the impact of an interruption by the number of affected customers divided by the total number of customers, the impact is scaled by the kVA of the load affected divided by the total kVA of the load connected to the network. The associated measures for the average duration and frequency of the sustained interruptions are Average System Interruption Duration Index (ASIDI) and Average System Interruption Frequency Index (ASIFI).[56]

Box 7.2: Load based distribution reliability measures that may be used[57]

ASIDI or **Average System Interruption Duration Index** is similar to *SAIDI* except that it is based on load (kVA) rather than numbers of *Customers*.

ASIFI or **Average System Interruption Frequency Index** is similar to *SAIFI* except that it is based on load (kVA) rather than numbers of *Customers*.

55 Section 3.2.4 of the Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

56 Section 3.3 of the Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

57 Italicised terms used in these definitions have the meanings given in the National Electricity Rules unless otherwise defined in this Part 2 of Appendix B.

In principle, distribution network incentive schemes, bench-marking and reporting schemes could use ASIDI and ASIFI instead of the usual SAIDI and SAIFI. However, these measures are not so commonly used internationally, which would limit the ability to make international comparisons.

Also, calculating the ASIDI and ASIFI measures requires the kVA of the load affected by each sustained interruption and the total kVA connected to the network. Estimates of the total load would require either SCADA[58] measurements of the system load or a set of registered capacities for each of the system loads. This may be practical in some networks with a small number of customers but is likely to be impractical in larger networks such as the distribution networks in the NEM, especially if the distributor does not have an extensive SCADA system. Other approaches for calculating ASIDI and ASIFI could be to measure the size of the interrupted load in annual kWh or the installed kVA, rather than actual kVA at the time of the interruption. Both these changes could make the calculation easier to implement.

For these reasons we are not proposing to recommend the use of load based distribution reliability measures.

58 System Control And Data Acquisition is a system that provides remote monitoring of the network as well as some level of remote control of the network.

8 Proposed implementation plan

In addition to preparing this advice, we have considered how the set of common definitions for distribution reliability measures should be implemented and maintained in the future.

We consider that the most benefit from the set of common definitions would occur if it is widely adopted. Therefore, we would propose that the definitions form a non-binding guideline that could be referenced whenever an economic incentive, bench-marking or reporting scheme that adopts the definitions is being specified and applied. Being a non-binding guideline, it would not limit the adoption of alternative distribution reliability measures, should such measures be regarded as appropriate in specific circumstances.

We also consider that it would be desirable to provide a process for maintaining the definitions into the future. While we have aimed to provide flexibility in the definitions, it is likely that some amendments to the existing definitions or some additional definitions may be required to reflect changes in how the reliability measures are applied and changes to the associated assumptions that underlie the measures. For example, the definitions may need to be amended if there are improvements in the understanding of the impact of interruptions on customers or there are future technological improvements, such as innovations in distribution automation systems or the systems that monitor interruptions.

We also note that changes to this guideline, or its application, may result in a discontinuity in historical reliability data. This discontinuity could be removed if the distributors recast their historical data sets with the new classifications. While this may not necessarily be administratively burdensome, the cost of recasting should be taken into account when considering the benefits of changes to the definitions.

We would propose that the mechanism for implementing and maintaining a non-binding guideline for the reliability measures be set out in the NER, including a requirement for public consultation whenever the guideline is reviewed. Given the proposed application of the measures, we consider that the most appropriate entity to be given the role of drafting, publishing and maintaining the guideline is the AER. Further we propose that, as we are undertaking wide stakeholder consultation, the common set of definitions contained in our final report should form the initial guideline.

Accordingly, we are seeking stakeholders' views on the following questions:

- should the common definitions for distribution reliability measures be maintained in a non-binding guideline;
- should the mechanism for implementing and maintaining such a guideline be set out in the NER; and

- should the entity responsible for drafting, publishing and maintaining the guideline be the AER or another entity?

A Members of the advisory stakeholder working group

Representative	Stakeholder
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B Common definitions for distribution reliability measures

This appendix contains the proposed definitions for the distribution reliability measures. Italicised terms used in this Appendix B have the meanings given in the NER unless otherwise defined in Part 2 of Appendix B to this report.

Part 1 Measurements – SAIDI, SAIFI, MAIFI and MAIFIe

SAIDI or **System Average Interruption Duration Index** in respect of a relevant period, means the sum of the durations of all the *Sustained Interruptions* (in minutes) that have occurred during the relevant period, divided by the *Customer Base*.[59]

SAIFI or **System Average Interruption Frequency Index** in respect of a relevant period, means the total number of *Sustained Interruptions* that have occurred during the relevant period, divided by the *Customer Base*.[60]

MAIFI or **Momentary Average Interruption Frequency Index** in respect of a relevant period, means the total number of *Momentary Interruptions* that have occurred during the relevant period, divided by the *Customer Base*, provided that *Momentary Interruptions* that occur within the first three minutes of a *Sustained Interruption* are excluded from the calculation.

MAIFIe or **Momentary Average Interruption Frequency Index event** in respect of a relevant period, means the total number of *Momentary Interruption Events* that have occurred during the relevant period divided by the *Customer Base* for the relevant period, provided that *Momentary Interruptions* that occur within the first three minutes of a *Sustained Interruption* are excluded from the calculation.

Notes

When calculating *SAIDI*, *SAIFI*, *MAIFI* and *MAIFIe*:

- **Exclusions** – One or more of the circumstances numbered 1 to 7 in Part 3 of this Appendix B may be excluded from such calculations.
- **Interruptions** – The *Interruptions* used to calculate such measurements may be limited to *Planned Interruptions* or *Unplanned Interruptions*.
- **Major Event Days** – *Interruptions* that occur on a *Major Event Days* may be excluded from such calculations.
- **Feeders** – The calculations may be limited to *CBD feeders*, *urban feeders*, *short rural feeders*, *long rural feeders* or a combination of such *feeders*.

59 *Momentary Interruptions* are excluded from the calculation of *SAIDI*

60 *Momentary Interruptions* are excluded from the calculation of *SAIDI*

Part 2 - Definitions

Catastrophic event means a large scale event (such as a cyclone, flood or bushfire) that is identified by:

- applying a 4.15 multiple to the log standard deviation used in the statistical method set out in section 3.5 of the *IEEE Guide*; or
- such other statistical method determined by the regulator to more accurately identify large scale events.

CBD feeder means a *feeder* in one or more geographic areas that have been determined by the relevant participating jurisdiction as supplying electricity to predominantly commercial, high-rise buildings, supplied by a predominantly underground *distribution network* containing significant interconnection and redundancy when compared to urban areas.

Customer means an end user of electricity who purchases electricity *supplied* through a *distribution system* to a *connection point*.

Customer Base in respect of a relevant period, means:

- the number of *Distribution Customers* as at the start of the relevant period; plus
- the number of *Distribution Customers* as at the end of the relevant period,

divided by two.[61]

Distribution Customer means a *connection point* between a *distribution network* and *Customer* that has been assigned a *NMI*, including energised and de-energised *connection points* but excluding *unmetered connection points*.

feeder means a power line, including underground cables, that is part of a *distribution network*.

IEEE Guide means the 'IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Std 1366-2012' published by the Institute of Electrical and Electronic Engineers on 31 May 2012.

Interruption means any loss of electricity supply to *Distribution Customers* associated with an *outage* of any part of the *network*, including *outages* affecting a single *Customer's* premises but excluding *disconnections* caused by a *retailer* or a fault in electrical equipment owned by a *Customer*, provided that:

- the start of an *Interruption* is taken to be when the *Interruption* is initially automatically recorded by equipment such as *SCADA* or, where such equipment does not exist, at the time of the first *Customer* call reporting that there has been an *outage* in the *network*; and

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61 Indices are calculated on whichever reporting period is required.

- the end of an *Interruption* is taken to be when the *Interruption* is automatically recorded as ending by equipment such as *SCADA* or, where such equipment does not exist, the time when electricity supply is restored to affected *Distribution Customers*.[62]

long rural feeder means a *feeder* with a total feeder route length greater than 200 km, which is not a *CBD feeder* or *urban feeder*.

Major Event Day has the meaning given in the *IEEE Guide*, provided that:

- for the purposes of applying an economic incentive scheme, the regulator may apply a different multiple of log standard deviation than the 2.5 multiple used in the statistical method set out in section 3.5 of the *IEEE Guide* should such multiple be determined by the regulator to more accurately reflect the normal operation of the *distribution network*; and

- *Catastrophic events* may be excluded from the statistical method used to classify *Major Event Days*.

Momentary Interruption means an *Interruption* to a *Distribution Customer's* electricity supply with a duration of 3 minutes or less, provided that the end of each *Momentary Interruption* is taken to be when electricity supply is temporarily restored or, in the absence of a temporary restoration of supply, when supply is successfully restored

Momentary Interruption Event means one or more *Momentary Interruptions* that occur within a continued duration of 3 minutes or less, provided that the successful restoration of electricity supply after any number of *Momentary Interruptions* is taken to be the end of the *Momentary Interruption Event*.

National electricity legislation has the meaning given in the *National Electricity Law*.

outage means the loss of ability of a component to deliver power.

Planned Interruption means an *Interruption* resulting from a *Distribution Network Service Provider's* intentional interruption of electricity supply to a *Customer's* premises where the *Customer* has been provided with prior notification of the *Interruption* in accordance with all applicable laws and regulations.

SCADA or **Supervisory Control and Data Acquisition** means a system employed to gather and analyse real-time data in respect of *network* related infrastructure.

short rural feeder means a *feeder* with a total feeder route length less than 200 km, which is not a *CBD feeder* or *urban feeder*.

Sustained Interruption means an *Interruption* to a *Distribution Customer's* electricity supply that has a duration longer than 3 minutes, provided that the successful restoration of supply to the *Distribution Customer* during such duration is taken to be the end of the *Sustained Interruption*.

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62 The number of affected *Customers* during an *Interruption* may need to be estimated

Unplanned Interruption means an *Interruption* that is not a *Planned Interruption*.

urban feeder is a *feeder* which is not a *CBD feeder* and has a weather normalised maximum demand over the feeder route length greater than 0.3 MVA/km.

Part 3 - Exclusions

Interruptions that result from the following circumstances may be excluded from the calculation of *SAIDI*, *SAIFI*, *MAIFI* and *MAIFIe*:

1. *Load shedding* due to a *generation* shortfall.

2. Automatic *load shedding* due to the operation of under-frequency relays following the occurrence of a *power system* under-frequency condition.

3. *Load shedding* at the direction of *AEMO* or a *System Operator*.

4. *Load* interruptions caused by a failure of the shared *transmission network*.

5. *Load* interruptions caused by a failure of *transmission connection assets* except where the interruptions were due to inadequate planning of *transmission network connections points* and the *Distribution Network Service Provider* is responsible for the planning of *transmission network connection points*.

6. *Load interruptions* caused by the exercise of any obligation, right or discretion imposed upon or provided for under *jurisdictional electricity legislation* and *national electricity legislation* applying to a *Distribution Network Service Provider*.

7. *Load* interruptions caused by, or extended by, a direction from state or federal emergency services.