Australian Energy Market Commission

REVIEW

FINAL REPORT

Review of Distribution Reliability Measures

5 September 2014

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Final Report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

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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

Currently, reliability measures are separately defined by the Australian Energy Regulator (AER) and certain jurisdictions and, as such, it is difficult to compare the reliability performance across the National Electricity Market (NEM). Therefore, the COAG Energy Council (formerly called the Standing Council on Energy and Resources) requested that the AEMC develop common definitions for distribution reliability measures for application in the NEM.

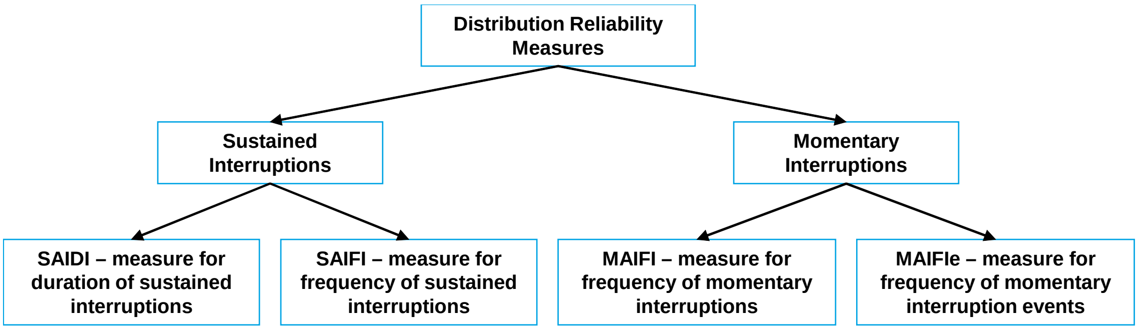
This report presents a menu of our recommended definitions of distribution reliability measures. These definitions could be practically applied by the distributors, jurisdictions, the AER and others. In general, the measures and the advice contained in this report:

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

Key distribution reliability measures

Figure 1 shows the way that the different distribution reliability measures can be divided into those that apply for sustained and momentary interruptions. The recommended measures for sustained interruptions are SAIDI and SAIFI, while the recommended measures for momentary interruptions are MAIFI and MAIFIe.

Figure 1 Overview of recommended distribution reliability measures



We recommend harmonised definitions for the key distribution reliability measures set out in Box 1, which impact on customers in terms of sustained[1] and momentary interruptions.[2]

The recommended change to the definition of a momentary interruption and a momentary interruption event[3] from less than one minute to less than three minutes

1 Supply is not restored quickly.

2 Supply is quickly restored, in a few minutes.

would increase the flexibility and options for distribution automation systems, which potentially reduces their cost. The AER and the distributors generally support our 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. Similarly various consumer advocacy bodies supported this change.

Further, we recommend harmonised supporting definitions for planned and unplanned interruptions, customers and interruptions.

Box 1: Key distribution reliability measures

We recommend common definitions for the following key distribution reliability measures for a reporting period:

- 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; and
- momentary average interruption frequency index event (MAIFIe), which measures the average frequency of momentary interruption events experienced by customers, where a momentary interruption event is one or more momentary interruptions within quick succession.

In addition we recommend that the definition of a momentary interruption and a momentary interruption event is changed from less than one minute to less than three minutes.

Detailed definitions for these measures are provided in Chapter 3 and Appendix B of this report.

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.

3 A series of one or more momentary interruptions within quick succession forming a single event.

There is currently broad agreement between the stakeholders on the definitions and treatment of exclusions. We recommend that exclusions be based on the current definitions used in the AER's Service Target Performance Incentive Scheme (STPIS).[4]

Similarly, there is currently broad agreement on the definitions and treatment of major event days. We recommend that major event days be identified using the 2.5 beta method[5], which is a statistical method for identifying those days where there was an unusually high impact from sustained interruptions. We also recommend 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 recommended common definitions, it is up to the party that is designing a distribution reliability incentive, benchmarking 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 most jurisdictions currently classify feeders as CBD, urban, short rural and long rural feeders. We are not recommending major changes to the current definitions as any material changes to the feeder classifications could re-classify a significant number of feeders and change the measured reliability for the affected feeder classifications. If this change were to be made in isolation, it would introduce risks to the distributors by:

- changing the revenue they would receive under their regulatory incentive schemes such as the AER STPIS; and
- potentially requiring them in make additional capital investments to restore the measured reliability performance to the required reliability targets.

In turn, these risks to the distributors may be passed onto costumers through the network use of system charges.

We recommend the following two incremental changes to the current classifications:

- The definition of urban feeder is currently based on actual historical loading and we recommend that this is changed to give the option to use a temperature adjusted historical 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 jurisdiction.

4 The obligations on the AER in relation to the STPIS are contained in clause 6.6.2 of the NER.

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

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 recommending such a change in isolation as it could lead to material risks for distributors and customers. We also recommend further review of the classification criteria.

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 recommend that the identification of lower reliability customers should be based on the reliability being persistently lower than average. In addition, we recommend 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 referred to 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 in certain circumstances and may require additional data collection systems to be established. Therefore, as they are not currently widely used internationally, we are not recommending their use in the NEM.

Recommended implementation plan

The recommended common definitions for distribution reliability measures in this report have the potential to improve the consistency and transparency of the various distribution reliability incentive, reporting and benchmarking 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. The wide adoption of the definitions in this report was supported by the submissions to our draft report.

We recommend that requisite changes be made to the National Electricity Rules (NER) to require the AER to:

- develop, publish and maintain a guideline for a common set of definitions for distribution reliability measures in the NEM (Distribution Reliability Measures Guideline);
- consult with stakeholders when developing and maintaining the Distribution Reliability Measures Guideline; and
- have regard to the Distribution Reliability Measures Guideline when developing the STPIS and preparing network service provider performance reports under

section 28V of the National Electricity Law[6] (for example, AER's Annual Benchmarking Report[7]).

We also recommend that the common definitions for distribution reliability measures set out in this report form the basis of the initial Distribution Reliability Measures Guideline.

Under the existing legislative framework, a requirement that jurisdictional standard setters and regulators adopt a given set of distribution reliability measures cannot be introduced into the NER. Nevertheless, we do encourage such standard setters and regulatory bodies to adopt the definitions set out in the Distribution Reliability Measures Guideline when undertaking reporting, bench-marking and managing incentive schemes.

Finally we suggest that the AER, and the relevant jurisdictional standard setters and regulatory bodies, provide reasons if they deviate from the definitions contained in the Distribution Reliability Measures Guideline. This would provide greater certainty to stakeholders as well as transparency and consistency in the application of distribution reliability measures.

Consultation

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 report. The group consisted of representatives from the AER, the Energy Networks Association (ENA) and various distributors. We held two workshops with the ASWG during the preparation of our draft report. In addition to the ASWG, we consulted with the jurisdictional governments, the Australian Energy Market Operator (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 containing our recommendations was published on 19 June 2014 for stakeholder consultation. We received 11 submissions from the AER, various distributors and consumer advocates. Our final report reflects the comments in these submissions.

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

6 The National Electricity Law forms a schedule to the National Electricity (South Australia) Act 1996.

7 The obligations on the AER in relation to the Annual Benchmarking Report are contained in rule 6.27 of the NER.

Contents

1 Introduction

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

Currently, reliability measures are separately defined by the Australian Energy Regulator (AER) and certain jurisdictions and, as such, it is difficult to compare the reliability performance across the NEM. Therefore, the COAG Energy Council (formerly called the Standing Council on Energy and Resources) requested that the Australian Energy Market Commission (AEMC or Commission) 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 (2013 Distribution Report).[8]

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 report:

- could be used by standard setters to set distribution reliability targets and other reliability measures;
- could be used by distributors 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 distributors in the NEM;
- would assist the AER in undertaking benchmarking, which can be considered in the development of its revenue determinations for each distributor;
- 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 report provide a menu of measures that can be applied by the AER, jurisdictions and others, as relevant for their particular application. Therefore, we recommend that these measures are widely adopted.

1.1 Scope of the review

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

8 This review is available on the AEMC's website at http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-national-framework-for-distribution.

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 distributors; 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 Energy Council.[9] Consequently, the COAG Energy Council requested that the AEMC develop common definitions for expressing distribution reliability targets across the NEM.

The menu of distribution reliability measures contained in this report could be used to provide greater consistency between the various existing applications of distribution reliability measures, including the AER's service target performance incentive scheme (STPIS)[10] and reliability performance benchmarking.[11]

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, relevant electricity distributors, jurisdictional regulatory bodies, and governments when preparing this advice. Further, where appropriate, the AEMC was requested to seek feedback from relevant transmission businesses and the Australian Energy Market Operator (AEMO).

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

10 The obligations on the AER in relation to the STPIS are contained in clause 6.6.2 of the NER.

11 The obligations on the AER in relation to the Annual Benchmarking Report are contained in rule 6.27 of the NER.

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

In addition to the ASWG, during the preparation of our draft report 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.

The terms of reference from the COAG Energy Council required the AEMC to provide its advice by 31 July 2014. This was subsequently extended to 5 September 2014 to allow more robust and comprehensive stakeholder engagement in development of this advice. This extension allowed us to publically consult on the common distribution reliability measure definitions prior to finalising our advice.[12]

Our draft report was published on 19 June 2014 for stakeholder consultation, with submissions on the draft report due by 18 July 2014. We received a total of eleven submissions from:

- the AER;
- Energex;
- Ergon Energy;
- CitiPower Pty and Powercor Australia Limited;
- Energy Networks Australia;
- SP AusNet;
- New South Wales Distribution Network Service Providers (NSW DNSPs);
- Alternative Technology Association (ATA);
- Public Interest Advocacy Centre (PIAC);
- Consumer Utilities Advocacy Centre Ltd (CUAC); and
- Ethnic Communities Council of NSW (ECC).

1.4 Structure of the report

This report is structured as follows:

- Chapter 2 sets out the principles and assessment framework that we used in preparing 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;

12 Letter granting an extension of time in relation to development of common definitions, received on 26 March 2014, available on the AEMC website at www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Reliability-Measures.

- 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 our recommended 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.

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 its 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 benchmarking 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 benchmarking requirements for distribution reliability measures, as well as the various jurisdictional reporting requirements. The ASWG assisted us with this process.

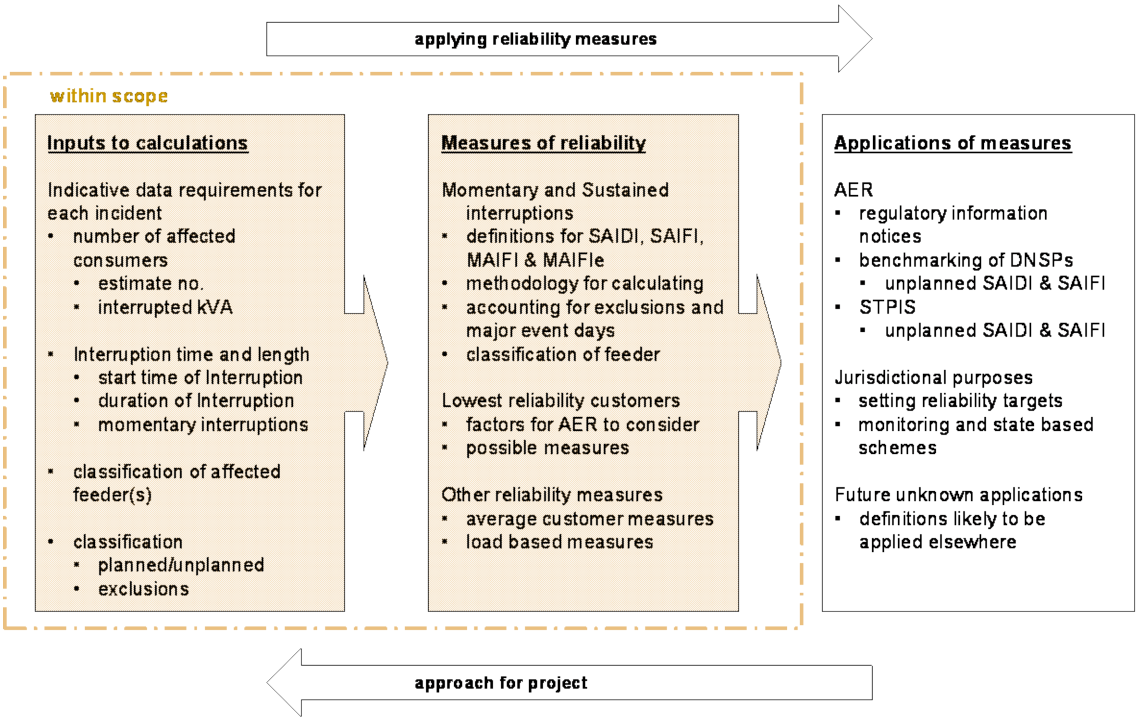
We compared the current distribution reliability measures to understand the differences between them with the aim of developing uniform definitions for all the commonly used distribution reliability measures, as well as the associated supporting definitions used when applying the measures.

When developing the common definitions we placed particular weight on the definitions used in the AER's 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 benchmarking, and we note that the

AER plans to update its STPIS.[13] We also considered the jurisdictional variations to these definitions and we had regard to the internationally accepted IEEE standard 1366 - 2012.[14]

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 we are not recommending changes to the regulatory 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



13 Page 2 of the AER's submission to our draft report.

14 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 recommended definitions for measuring sustained and momentary interruptions, and the necessary supporting definitions for these measures.

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 requires 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 distribution network usually 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. Momentary interruptions 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.

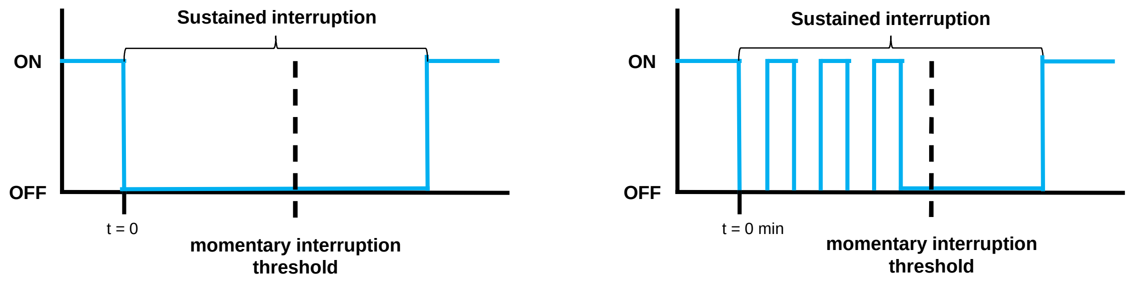
This chapter discusses two commonly applied measures for sustained interruptions, SAIDI and SAIFI, and two measures for momentary interruptions, MAIFI and MAIFIe. Our recommended definitions for these measures can be applied over any time period and for any subset of interruptions (such as unplanned 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 between the AER, jurisdictions, network businesses and consumer advocates on the definitions recommended in this report for 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 distributor' 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. In each case the duration of the interruption is greater than the momentary interruption threshold, which is explained further in section 3.2.

Figure 3.1 Sustained interruptions



Box 3.1 contains our recommended definition for a sustained interruption and recommended definitions for the commonly used measures for sustained interruptions, SAIDI and SAIFI.

Box 3.1: Definitions for distribution reliability measures for sustained interruptions[15]

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*.[16]

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*.[17]

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

15 Italicised terms used in these definitions have the meanings given in the NER unless otherwise defined in Part 2 of Appendix B.

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

17 *Momentary Interruptions* are excluded from the calculation of *SAIFI*.

distribution reliability reporting, benchmarking and incentive schemes, including the AER's current STPIS.

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

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 multiple sustained interruptions can have a significant impact on customers. For this reason SAIFI is a reliability measure that is used in most distribution reliability reporting, benchmarking 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 recommending any material changes to its definition.

3.1.3 Sustained interruptions - definition

The current AER documentation for its STPIS[18] and for benchmarking[19] 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 recommend that an explicit definition for a sustained interruption be used in respect of reliability measures. For the reasons given in section 3.2, we are recommending the duration of a momentary interruption as being defined as three minutes or less. Accordingly, we are recommending 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 are recommending 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.

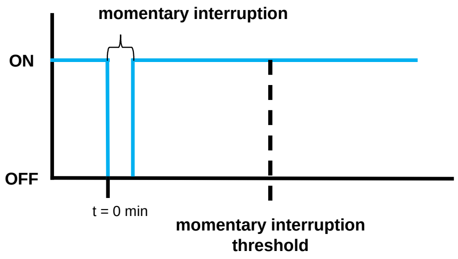
18 AER, *Electricity distribution network service providers - Service target performance incentive scheme*, November 2009.

19 The AER's document "Economic benchmarking RIN for distribution network service providers - Instructions and Definitions, November 2013" provides a description of its benchmarking data requirements.

3.2 Definitions and measures for momentary interruptions

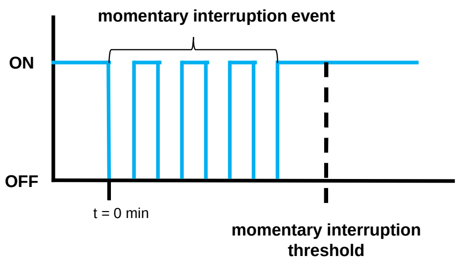
Generally, a momentary interruption is a brief loss of electricity supply to a customer caused by the opening and closing of a circuit breaker or similar device. This would typically happen following a successful operation of an auto-recloser or distribution automation systems. Figure 3.2 shows an example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



Box 3.2 contains our recommended definitions for a momentary interruption and a momentary interruption event, as well as the commonly used measures for momentary interruptions, MAIFI and MAIFIe. These measures reflect the average number of momentary interruptions and momentary interruption events experienced by customers, respectively.

3.2.1 MAIFI - a measure of the frequency of momentary interruptions

MAIFI measures the average frequency of momentary interruptions experienced by customers during the relevant 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.[20]

We are not recommending 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. This change to the definition of a momentary interruption is discussed in section 3.2.3.

Box 3.2: Definitions for distribution reliability measures for momentary interruptions[21]

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 restored for any duration.

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*.

In their submissions to our draft report the ATA, CUAC, and the ECC suggested that the momentary interruptions that occur at the start of a sustained interruption should not be excluded from the calculation of SAIDI and SAIFI as interruptions still have an impact on customers.[22] We note this concern but consider that the impact of one or more momentary interruptions at the beginning of a sustained interruption would be significantly less than the impact of the sustained interruption itself. This is also

20 In their submissions to our draft report the ATA, CUAC, and the ECC consider that the momentary interruptions should not be excluded from the calculation and classified as momentary interruptions. We do not agree and this issue is discussed in section 3.1.1.

21 Italicised terms used in these definitions have the meanings given in the NER unless otherwise defined in Part 2 of Appendix B.

22 Page 5 of the ATA submission, page 1 of the CUAC submission and page 1 of the ECC submission.

consistent with international standards that treat interruptions as either a momentary or sustained.[23]

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

MAIFIe measures the average frequency of momentary interruption events experienced by customers during the relevant 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.[24]

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

3.2.3 Momentary interruptions and momentary interruption events - definitions

The current AER documentation for its STPIS[25] and benchmarking[26] 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.

Allowing the duration of momentary interruptions and momentary interruption events to extend to three minutes would allow the distributors greater flexibility in the design of their distribution automation systems. For the majority of networks, where distribution automation systems have not yet been deployed in scale, this change would provide the potential to reduce the cost of implementing distribution automation systems. In conjunction with an effective incentive scheme, the increased flexibility and potential for reduced cost of distribution automation systems would be likely to promote greater investment in distribution automation systems. This increased investment in distribution automation would be expected to reduce the number of sustained interruptions by automatically restoring supply to more customers, thus improving reliability performance.

In their respective submissions to our draft report, the ENA, Energex and Ergon Energy agreed that increasing the duration to three minutes or less is likely to promote investment in distribution automation systems, and hence improve reliability for many customers.[27] In addition, Energex considered a threshold of three minutes would make

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

24 This is discussed further in section 3.1.1.

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

26 AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions, November 2013.

27 Page 2 of the ENA submission, page 1 of the CitiPower and PowerCor Australia submission, page 5 of the NSW DNSPs submission, page 1 of the attachment to the Energex submission and page 3 of the attachment to the Ergon Energy submission.

it technically feasible to introduce a central hierarchy-managed automation scheme. Such a scheme would be capable of automatically restoring supply to more customers in some circumstances and, hence, would improve reliability by lowering the number customers experiencing sustained interruptions.[28]

We note that the current IEEE standard[29] 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 European standards and to provide an incentive for distribution automation systems that could speed up restoration of supply for some customers.[30]

There is potential for a revised STPIS, aligned to the recommended changes to service measure definitions, to financially impact distributors who have responded to the existing incentives and already implemented distribution automation schemes. Should the recommended 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 commenced the design of its distribution automation in 2006, as well as Powercor and Citipower that have more recently commenced a distributed automation system roll-out. SP AusNet also noted in its submission that it would be difficult to reduce the threshold at a later date if significant levels of investment are based on a three minute threshold.

Therefore, **we are recommending 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 recommending to also align the definition of a sustained interruption to greater than three minutes. However, we do consider that the existing threshold of one minute could be retained where the relevant regulatory body considers that it would be in the best interests of customers in that jurisdiction.

Life Support Customers

The ATA, CUAC, PIAC and ECC generally supported the change of threshold to three minutes as it was unlikely to have a material impact on most customers. They did, however, also consider that the potential impact on life support customers should be investigated further with Physical Disability Australia.[31]

Physical Disability Australia confirmed that the life support equipment generally includes backup batteries which can last an hour or two when supply is interrupted, depending on their condition. The level of backup provided, such as spare ventilators and batteries, varies depending on the medical condition and other circumstances of the

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28 A central hierarchy-managed distribution automation scheme can make more "network aware" restoration decisions by considering the pre- and post-fault network conditions using a live network model, rather than just relying on local information for restoration decision making.

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

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

31 Page 6 of the ATA submission, page 1 of the CUAC submission and page 1 of the ECC submission.

life support customers.[32] The worst case scenario would be a life support customer living alone that is dependent on life support equipment (such as a ventilator).

The recommended change of a definition of momentary interruption, from less than one minute to less than three minutes, would not adversely impact life support customers directly, provided that they have the backup batteries or other equipment that would be necessary for a sustained interruption. We also consider that the recommended change would be expected to reduce the likelihood of a sustained interruption by promoting investment in distribution automation systems through greater flexibility in their design.

While the recommended change is likely to reduce the number of sustained interruptions, it is important to acknowledge that it is not economically feasible or even possible to eliminate sustained interruptions. This needs to be taken into account when determining the level of backup provided by life support equipment.

As a separate issue, it was suggested by the Physical Disability Australia representative that it would also be important to keep life support customers informed during a sustained interruption, particularly when they are reliant on battery backup. This could be achieved by providing such customers will a direct phone line to the distributor, as general inquiry lines may be overloaded during sustained interruptions.

3.2.4 The use of MAIFI and MAIFIe in benchmarking and economic incentive schemes

MAIFI counts all momentary interruptions, unless they occur at the beginning of a sustained interruption. 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.

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

32 This information was provided in the form of email and telephone communication with a member of the Australian Ventilator User's Network.

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. We also note that the susceptibility of individual appliances to momentary interruptions would vary significantly, depending on the nature of the appliance and the associated manufacturing standards.

In our draft report indicated that we considered that, for the purposes of incentive schemes on distributors, MAIFIe is a more preferable measure of momentary interruptions than MAIFI. This is because we considered that 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. This was supported by the ENA, CitiPower and PowerCor Australia, NSW DNSPs, Energex and Ergon Energy in their submissions on our draft report.[33]

The ATA, CUAC and ECC noted in their submissions that all momentary interruptions have impacts on customers, including wear and tear on motors which can shorten their life.[34] This is particularly true for older appliances or where the motor is driving a flywheel. Consequentially, the ATA, CUAC and ECC suggested that both MAIFI and MAIFIe are important measures for momentary interruptions.

In our final report we have provided recommended definitions for both MAIFI and MAIFIe, and remain of the view that generally MAIFIe provides a better regulatory signal than MAIFI. In a specific instance where distribution reliability is required to be measured as part of a reporting or regulatory incentive scheme, the relevant regulatory body or standard setter would need to decide how to treat momentary interruptions. This could include using MAIFI and/or MAIFIe, or not considering momentary interruptions at all.

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, customer base, and interruptions are discussed.

Currently, there are small differences between the various supporting definitions used in the NEM. We are recommending changes to these definitions in order to standardise them. Box 3.3 contains our recommended supporting definitions.

33 Page 2 of the ENA submission, page 1 of the CitiPower and PowerCor Australia submission, page 5 of the NSW DNSPs submission, page 1 of the attachment to the Energex submission and page 3 of the attachment to the Ergon Energy submission.

34 Page 4 of the ATA submission, page 1 of the CUAC submission and page 1 of the ECC submission.

Box 3.3: Supporting definitions[35]

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, rules 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.[36]

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* reports 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*.[37]

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.

35 Italicised terms used in these definitions have the meanings given in the NER unless otherwise defined in Part 2 of Appendix B.

36 Indices are calculated on whichever reporting period is required.

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

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 may 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 maintain the service life of the equipment. During periods of maintenance, one or more components of the network are often out of service which may necessitate a planned interruption to the supply to some customers. A distributor should undertake a prudent level of planned maintenance to manage the overall reliability performance of its 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 no 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 damage or 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 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 a planned interruption.[38] The notice requirements vary for jurisdictions that have not adopted the NECF.

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 jurisdictions.

We recommend 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

38 Section 90 of Part 4 of the National Energy Retail Rules

administrative burden, especially as very few connection points would be de-energised for the reporting period, typically an entire year.

Under the AER's current STPIS, and the majority of other jurisdictional applications, unmetered public lighting is not considered to be a customer for the purposes of calculating reliability measures. There is currently discretion as to whether other unmetered connection points are also treated as customers for the purposes of calculating reliability measures. In our draft report we proposed that the definition of customer 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 noted that incentive schemes do not generally target unmetered supplies as the reliability of the supply of unmetered loads such as public lighting are generally considered separately. We consider that adopting this definition for a customer would mean that the current inconsistencies in the definitions across the NEM would be removed going forward.

The ENA agrees that unmetered supplies should be excluded from the definition of a distribution customer but do note that this may cause material costs to some network businesses.[39] The ENA recommends that a transitional period be allowed for those network businesses that would be adversely affected by the recommended change to exclude all unmetered supplies. We agree with the ENA as the number of unmetered connection points is relatively small and would be unlikely to cause a material impact on distribution reliability measures. Therefore, we would advocate allowing a transition to our recommended definition.

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 that is generally applied currently.

An alternative to taking this average would be to keep a record of the total customers on each feeder for each day, calculate a daily reliability measure and then to summate the daily values to give an annual measure. This approach is supported by NSW DNSPs.[40] We consider that this alternative approach would provide more accurate reliability measures for individual feeders but would be unlikely to make a material difference across a distribution network. Also, the alternative approach would require more burdensome record keeping and some distributors would not currently have the systems to record such information.

We recommend that the simpler approach of averaging the number of customers over the period of interest be used for reporting and benchmarking in order to provide more consistent measures of distribution reliability.

39 Page 4 of the ENA submission.

40 Page 3 of the NSW DNSPs submission.

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 recommend 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 estimation 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 recommended 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. For example, while many customer appliances will not operate during a brownout (very low voltage), this is treated as a power quality issue rather than a reliability issue. This is generally consistent with current approaches and international standards.[41] 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. This approach would be inconsistent with our recommended definitions.

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[42] or, where such equipment does not exist, at the time of the first customer call relating to the network outage.[43] The recommended definition is based on this approach and includes a similar definition for the end of the interruption. The accuracy for measuring the duration of interruptions would be expected to improve if a significant numbers of smart meters are deployed.

In our draft report we proposed a definition of interruption that excluded disconnections caused by a retailer, for example for non-payment of bills. In its submission the ENA suggested that the definition of interruptions should exclude disconnections permitted under the NECF for both retailers and distributors.[44] While we agree that there may be circumstances where disconnections effected by a

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

42 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.

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

44 Page 4 of the ENA submission.

distributor in accordance with the NECF should be excluded from the calculation of interruptions for the purposes of reliability standards, we note that:

- not all jurisdictions have adopted the NECF and, accordingly, the regulatory framework for permitted disconnections differs in certain jurisdictions; and
- there may be circumstances where a disconnection in accordance with the NECF should, nevertheless, still be counted towards the distributors reliability performance (an example would be interruption due to a safety issue in the network).

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 interruptions, or the impact of the interruptions, that are outside the control of the distributor; and
- major event days are days are interruptions on that day are not regarded as representative of daily operation, usually due to severe 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, benchmarking 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. It is normal to remove the interruptions covered by the exclusions from the calculation of reliability measures when the focus is on the performance of the distributor on those areas it is considered as being within the distributor's 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 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 benchmarking 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 contains our recommended definitions of exclusions.

Box 4.1: Definitions for exclusions[45]

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 or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of, the *network* did not cause, in whole or part, the event giving rise to the direction.

The AER's current STPIS includes the first six exclusions from Box 4.1[46] and the same exclusions are also used by the AER for benchmarking.[47] 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[48] to be:

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

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

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

48 National Electricity Law (South Australia 1996).

> "**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, in our draft report we proposed that an additional exclusion for load interruptions caused by, or extended by, a direction from emergency services be added to the numbered list of exclusions above. We note that the need for an emergency services officer to issue a direction to a distributor 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. We also noted that this is exclusion is consistent with the AER's transmission STPIS.[49]

In its submission to our draft report the ATA suggested that the proposed exclusion for directions by emergency services should be clarified so that it does not apply in cases where a 'non-excluded' event has caused or contributed to the fault situation.[50] We agree that this was the policy intent of including this exclusion and have amended this exclusion to only apply where the relevant distributors have not contributed to the need for the direction.

The ENA proposed an additional possible exclusion that follows from the proposed role for a Metering Coordinator[51] that is being considered as part of the Expanding competition in metering and related services rule change.[52] The ENA recommends that interruptions caused by the actions of a Metering Coordinator should also be treated as an exclusion.

The role of the Metering Coordinator and the associated framework are still being developed through the Expanding competition in metering and related services rule change. Therefore, while we agree in principle with the ENA, we are not recommending a specific exclusion for the actions of Metering Coordinator at this time as the related framework for the Metering Coordinator is still the subject of a rule change.

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

50 Page 8 of the ATA submission.

51 Page 4 of the ENA submission.

52 Further information on this rule change proposal is available on the AEMC's website at www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

4.2 Major event days

4.2.1 Treatment of major event days

Generally, major event days are days on which the distribution network experience 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.

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.[53] The AER also allows interruptions to be removed from the reliability data for major event days as part of its benchmarking.[54]

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.

Box 4.2 contains our recommended definitions of major event days and catastrophic events.

4.2.2 Identifying major event days - the IEEE 2.5 beta method

For its current STPIS and its benchmarking, the AER requires that the 2.5 beta method is used to identify major event days.[55] This method is defined in the IEEE Standard 1366-2012[56] and is applied in many countries.

The 2.5 beta method is a statistical method that identifies those days in the reporting period that have unusually high unreliability. The IEEE chose the 2.5 beta method because it captured the days with major interruptions consistently across a range of different distribution networks regardless of their size, geography or design. The method works well because the daily impacts of distribution interruptions typically follow a log-normal distribution, which makes it possible to drawn statistical inferences and comparisons.

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

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

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

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

Box 4.2: Definitions for major event days and catastrophic events[57]

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 (discussed in section 4.2.3) 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.

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.

Under the IEEE method, a major event day is defined as a day where the daily SAIDI[58] 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;
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.

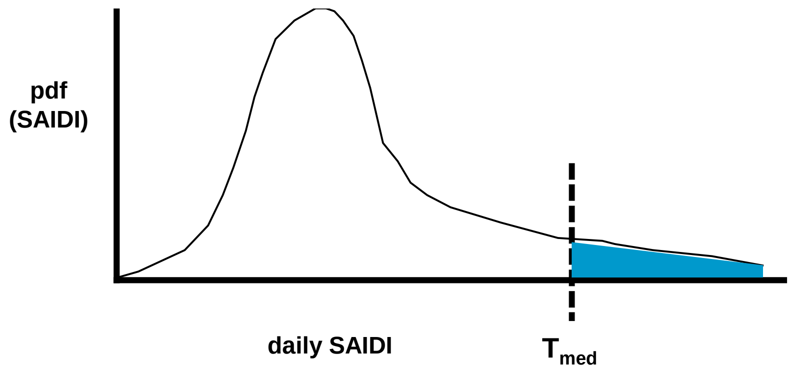
Figure 4.1 shows a typical probability distribution function (pdf) for the daily SAIDI values for a given period. Under the 2.5 beta method the value of the major event day

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

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

threshold T_{med} is calculated from this distribution of daily SAIDI values. The shaded area is where the daily SAIDI exceeds T_{med}, which represents the small number of days identified as major event days.

Figure 4.1 Probability of a major event day



The value of 2.5 would be expected to identify 2.3 days on average in a given period. This value was chosen by the IEEE because, while arbitrary, it consistently identifies those days that would generally be regarded as having unusually high unreliability.[59]

Figure 4.2 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[60] 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).

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.[61] 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,[62] where a higher major event day threshold may better identify those days where the distribution network experienced stresses beyond that normally expected.

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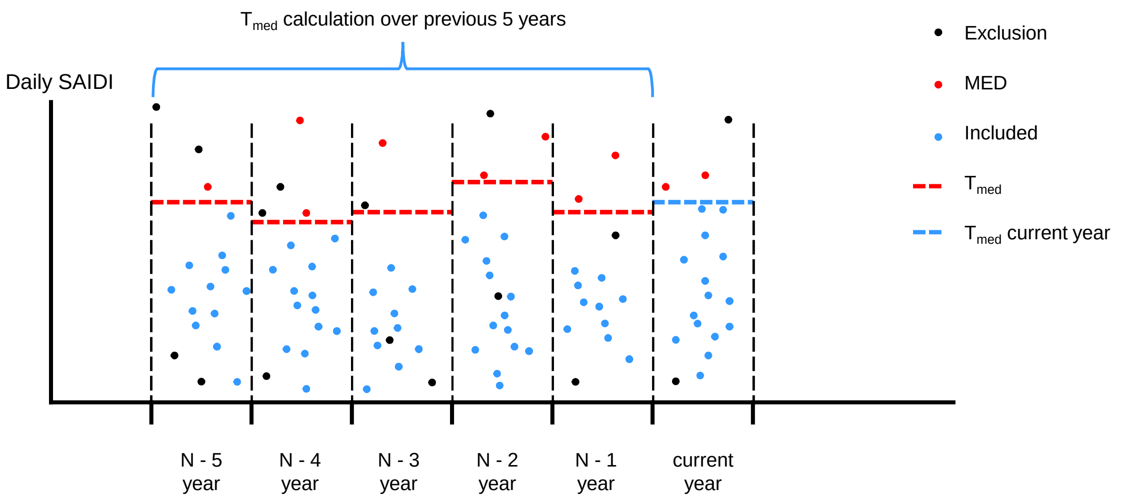
59 Section B.6.1 of the Institute of Electrical and Electronic Engineers, *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012.

60 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.

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

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

Figure 4.2 The 2.5 beta method for identifying major event days



In our draft report we proposed that the 2.5 beta method described by the IEEE, and referred in the AER's STPIS, be used for benchmarking and be the default method to be used when applying an economic incentive scheme to the distributor. In addition, we also proposed 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, which 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.

In its submission to our draft report the AER expressed its concern the proposed treatment of major event days could be interpreted as limiting the AER's discretion to consider alternative methods for addressing (or not addressing) major event days.[63] We note the AER's concerns but consider that the recommended approach is widely used internationally and reflects current practice in the NEM, and therefore should be included in this set of common definitions. The AER would be free to consider alternative approaches in its future reviews of its STPIS but any changes should be reflected in this set of common definitions in order to retain consistency and transparency in the measurement of distribution reliability for reporting, benchmarking and economic regulation.

63 AER submission to the draft report.

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.[64] 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 were developed but no definitive method was identified.[65] However, we understand that the 4.15 beta method has proven to work in many instances.[66] 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. The value of 4.15 appears to be somewhat arbitrary but IEEE’s experience is that the 4.15 beta method identifies events would have been chosen as catastrophic on qualitative grounds.

Figure 4.3 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).

We recommend 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 recommend 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 recommend that a catastrophic event ends when the distributor

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

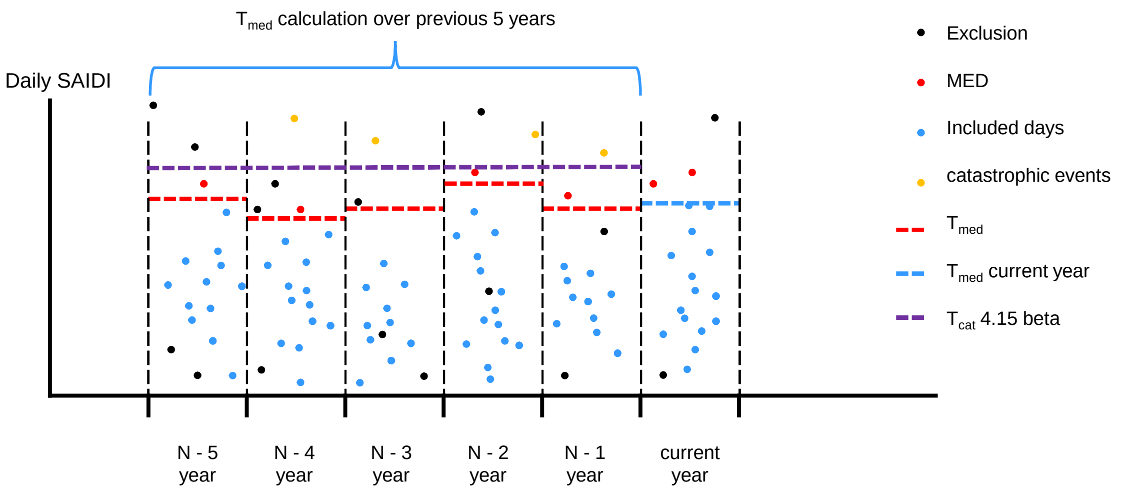
65 Section 5.3 of the *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366-2012, 31 May 2012. We also discussed identifying catastrophic days with an IEEE representative.

66 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

declares the end of the emergency condition, as defined by the relevant emergency management plan.

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}.

Figure 4.3 Including catastrophic events when identifying major event days



4.3 Application of exclusions and major event days

Section 4.1 describes the 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 the overall objective of the application of the distribution reliability measures, and on the intent of the regulatory body or distributor designing the associated economic incentive, benchmarking 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's network 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. More specifically, when implementing an incentive scheme, it is 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 interruptions are generally not included in current 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 benchmarking

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 benchmarking 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 event days 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, such as a transmission business, 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[67] on the basis of their location or customer density. Classification also enables performance across distribution networks to be more closely compared.

The AER and many of the 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.

We are not recommending significant changes to the current definitions used by the AER and many of the jurisdictions. This is because no approach that could be universally applied emerged from our analysis. We also do not recommend that material changes to the method for classifying feeders is made in isolation of a review of the associated reliability targets and incentive schemes.

Box 5.1: Definitions for feeder classifications[68]

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 maximum demand (which can be weather normalised) 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*.

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

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

5.1 Current Approach

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 benchmarking 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 categorisation of feeders was not widely supported but there was no common theme to alternative proposals."[69] This classification system is adopted in the majority of the 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;[70]

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

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

- Tasmania, which classifies on a customer or community basis.

These 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 recommended 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.

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, benchmarking 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.

In our draft report we proposed that the feeder load density should be calculated from the temperature normalised maximum demand, rather than the actual historical loading. We considered this would reduce the volatility of the classification of some rural and urban feeders. We also considered that the change would be unlikely to introduce a significant burden on the distributor businesses.

CitiPower and Powercor, Energex, Ergon Energy and the ENA supported the proposal to temperature normalised maximum demand when determining the classification of a feeder.[71] They indicated that this would provide greater certainty for some network investment decisions.

The NSW DNSPs did not consider that there is a business case for them to temperature normalise the feeder maximum demands as this would be resource intensive.[72] The ENA also noted NSW DNSPs concerns and suggested that temperature normalising of the feeder maximum demand should be optional.

We are recommending that the use of temperature normalising of the maximum demand should be optional. We consider that this would not introduce a material discontinuity in the historical reliability data used for benchmarking as the change mainly removes noise in the classification process, rather than introducing a systemic bias. We do however consider that the proposed approach should be agreed with the relevant regulator prior to its application to prevent the distributor from choosing whether to temperature normalise the maximum demands depending on the circumstances that year.

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 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 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 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,

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71 Page 2 of the CitiPower and Powercor submission, page 6 of the attachment to the Energex submission, page 11 of the attachment to the Enrgon Energy submission and page 5 of the ENA submission.

72 Page 7 of the NSW DNSPs submission.

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 regulatory bodies, 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 the median demand of a 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 this change were to be made in isolation, it would introduce risks to the distributors by:

- changing the revenue they would receive under their regulatory incentive schemes such as the AER STPIS; and
- potentially requiring them in make additional capital investments to restore the measured reliability performance to the required reliability targets.

In turn, these risks to the distributors may be passed onto costumers through the network use of system charges.

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 recommending that the relevant 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.

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.

5.3 Need for further analysis

In our draft report we indicated that we anticipated that the distributors would provide further analysis into different approaches for classifying urban and rural feeders. We understand that further analysis was undertaken by the distributors but a robust approach to classifying feeders was not identified. AusGrid's preliminary analysis considers that distance (the length of the feeder) was the criterion that could most satisfactorily classify most feeders, while Endeavour Energy and Essential Energy considered that certain feeders could not be easily classified by distance alone.[73]

The ENA, NSW DNSPs, Ergon Energy and SP AusNet support further work on the classification of feeders, particularly the distinction between urban and rural feeders.[74]

We also understand that the AER is considering reviewing various aspects of its STPIS, and this 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.

Therefore, we recommend that further analysis of different criterion for classifying feeders should be undertaken, with the best time for this analysis likely to be when the AER reviews its distribution network STPIS.

If a material change to criteria for classifying feeders were to be made then it would be desirable for the reliability targets to also be reviewed. This would be necessary in order to ensure that these targets align with the expectations and requirements of customers. Reviewing the reliability targets following a review of feeder classification criterion would also be desirable to ensure it did not cause the need for excessive network investments.

73 Page 7 of the ENA submission.

74 Page 2 of the CitiPower and Powercor submission, page 6 of the attachment to the Energex submission, page 11 of the attachment to the Enrgon Energy submission and page 5 of the ENA submission.

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 tends to reward 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 contained in Box 6.1 are important in identifying the customers with the lowest reliability.

Box 6.1: Principles for considering lowest reliability customers

We are recommending 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, except where it can be shown (to the AER) that it is in the long-term interest of consumers to consider any unique characteristics of the network.
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

In our draft report we proposed that the factors that need to be taken into account when identifying the lowest reliability customers should ideally be able to be applied in a consistent manner across all jurisdictions and distribution networks. This would allow all customers to be treated a consistent basis. While Energex generally agrees with the principle, Energex and NSW DNSPs consider that each DNSP's circumstances are unique.[75]

We still consider that the treatment of lowest reliability customers should be undertaken on a consistent basis, where this is practicable. However, it would be appropriate to acknowledge the unique characteristics of a network where it can be demonstrated to the AER it would be in the long-term interests of customers to do so.

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, benchmarking 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 electrical 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

75 Page 7 of the attachment to the Energex submission and page 8 of the NSW DNSPs submission.

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 as 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.

While Energex agrees that focussing feeder sections would better differentiate low performance, the number of feeder sections involved could be substantial and it could be burdensome to report on feeder sections.[76] We agree that considering feeder sections would require more substantial record keeping. This should be taken into account by the AER.

Also customers are generally more adversely affected by unplanned interruptions, compared to planned interruptions. Therefore, in our draft report we proposed that the measures of customer reliability used for considering lowest reliability should be based on unplanned SAIDI or SAIFI.

Ergon Energy cited customers surveys that indicated that residential customers place comparable value on the duration and frequency of interruptions (as measured by SAIDI and SAIFI respectively), while business customers place greater value on the frequency of interruptions over their duration.[77] The ATA considers that the approach for the lowest reliability of customers should also include MAIFI as customers are also impacted by the number of momentary interruptions experienced.[78]

We agree with the ATA that momentary interruptions can be important to customers but the largest impacts on customers would still be expected to be for sustained interruptions. We also note Ergon Energies comments about the relative importance of SAIDI and SAIFI. This indicates that, if a single measure of reliability is required, SAIFI would appear to best reflect the impacts on customers.

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

76 Page 8 of the attachment to the Energex submission and page 8 of the NSW DNSPs submission.

77 Page 7 of the attachment to the Ergon Energy submission and page 8 of the NSW DNSPs submission.

78 Page 9 of the ATA Ergon Energy submission and page 8 of the NSW DNSPs submission.

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.

Energex agreed that the experience of the lowest reliability customers, compared to average, should be considered on the basis of a given feeder classification.[79] We concur as it would make little sense to directly compare the reliability outcomes of customers on remote feeders with those in an urban area.

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 feeders (or feeder sections) that supply the customers with the lowest reliability. 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);

79 Page 8 of the attachment to the Energex submission.

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 in a similar manner to some guaranteed service level (GSL) schemes.

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);[80]

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. the percentage of customers experiencing n or more sustained interruptions per year (CEMIn);[81] 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, benchmarking 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.[82]

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

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

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

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.

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 report are generally suitable to be applied in the context of the NEM, 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 distributors. We have examined other measures that have been used internationally, in particular, those in the IEEE standard.[83]

The distribution reliability measures presented in this chapter may be suitable in some specific circumstances but each has short-comings and we are not recommending that these measures be used in the NEM. This position is supported by submissions to our draft report.

The short-comings of the distribution reliability measures presented in this chapter are discussed below.

7.1 Customer based distribution reliability measures

The SAIDI and SAIFI measures discussed in this 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). Box 7.1 contains three similar measures that express the impact of sustained interruptions on a customer basis. For the reasons below we are not recommending the use of these customer based distribution reliability measures.

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.[84]

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

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

84 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.

SAIFI indicate improved reliability experienced by customers, the CAIDI would rise, which could imply increased unreliability.

Box 7.1: Customer based distribution reliability measures that may be used[85]

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*).[86]

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

7.1.2 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.[87]

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

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

86 *CAIDI* excludes *momentary interruptions*.

87 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.

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.[88]

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. Box 7.2 contains the associated measures for the average duration and frequency of the sustained interruptions which are Average System Interruption Duration Index (ASIDI) and Average System Interruption Frequency Index (ASIFI) respectively.[89]

Box 7.2: Load based distribution reliability measures that may be used[90]

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*.

In principle, distribution network incentive schemes, benchmarking 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.

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88 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.

89 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.

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

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[91] 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 recommending the use of load based distribution reliability measures.

91 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 Implementation plan

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

8.1 Adoption of the recommended measures

We consider that the most benefit from the set of common definitions would occur if it is widely adopted. We proposed in our draft report that the definitions form a non-binding guideline that could be referenced whenever an economic incentive, benchmarking or reporting scheme that adopts the definitions is being specified and applied.

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 contained in this report, 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.

Therefore, in our draft report we proposed that the mechanism for implementing and maintaining a guideline for the reliability measures be set out in the NER, including a requirement for public consultation whenever the guideline is reviewed. Also, we proposed that the most appropriate body to be given the role of drafting, publishing and maintaining the guideline is the AER. Further, as the review process has involved wide stakeholder consultation, we proposed in our draft report, and remain of the view, that the common set of definitions contained in this final report should form the basis of the initial guideline.

In its submission to our draft report, the ATA considered that the set of common definitions for distribution reliability measures definitions should be binding in order to meet:[92]

- the requirements of the COAG Energy Council's terms of reference that the Commission have regard to "the need for consistency in setting and reporting on the distribution reliability targets across the NEM"; and
- the objective of the AEMC's principle (as set out in section 2.1) to "provide consistency and transparency in the calculation of distribution reliability measures to allow meaningful reporting and benchmarking exercises to occur".

While we agree that there would be benefits to widely applying the set of common definitions, it is not possible under the existing legislative framework to require the standard setters and other regulatory bodies of jurisdictions to adopt a given set of distribution reliability measures. This is discussed further in section 8.3.

92 Page 10 of the ATA submission.

The ENA also considered that the more widely the consistent distribution reliability measures are adopted, the greater will be the benefits to customers.[93] The ENA also suggested in their submission that the COAG Energy Council:

- endorses the definitions of the distribution reliability measures;
- agrees an implementation process that includes consultations on the applicable definitions for Western Australia and the Northern Territory; and
- agrees a program for amending legislation and regulatory arrangements.

In their submissions to our draft report, Energex and the NSW DNSPs agreed that the common definitions should form part of a non-binding guideline, but that the DNSPs should be able to choose the most appropriate measures for their network and jurisdictional requirements.[94]

Further, the ATA, ENA, Energex and the NSW DNSPs agree that the AER should be given the responsibility to maintain these definitions on an ongoing basis.

8.2 Implementation issues

We also note that changes to the definitions of reliability measures set out in this report, or their 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.

The ATA suggested that the natural differences between and within jurisdictions in respect of distribution networks could be accommodated by different target levels that suit a region, rather than requiring variations in the form of the definitions being applied in each jurisdiction.[95]

The NSW DNSPs noted that the recommended definitions for distribution reliability measures are different from the current definitions used for both the STPIS and the NSW distribution licence conditions and suggested that the following issues should be considered as part of an implementation plan:[96]

- historical reliability metrics for benchmarking purposes will need to be re-cast to enable comparison to new metrics;
- STPIS targets and actuals will need to be calculated with consistent definitions to ensure that DNSPs are not rewarded or penalised for changes to reliability definitions or categorisation;
- the licence conditions for NSW are based on historical performance; and
- jurisdictional licence conditions may need to change to be reviewed to prevent a step change in performance from triggering over or under investment.

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93 Page 6 of the ENA submission.

94 Page 10 of the attachment to the ENA submission and page 8 of the NSW DNSPs submission.

95 Page 10 of the ATA submission.

96 Page 8 of the NSW DNSPs submission.

8.3 Recommendations

Having regard to the submissions made to our draft report and the COAG Energy Council's terms of reference, we recommend that the NER be amended to require the AER to:

- develop, publish and maintain a guideline for a common set of definitions for distribution reliability measures in the NEM (Distribution Reliability Measures Guideline);
- consult with stakeholders when developing and maintaining the Distribution Reliability Measures Guideline; and
- have regard to the Distribution Reliability Measures Guideline when developing the STPIS and preparing network service provider performance reports[97] (for example, AER's Annual Benchmarking Report[98]).

We also recommend that the common definitions for distribution reliability measures set out in this report form the basis of the initial Distribution Reliability Measures Guideline.

Under the existing legislative framework, a requirement that jurisdictional standard setters and regulators adopt a given set of distribution reliability measures cannot be introduced into the NER. Nevertheless, we do encourage such standard setters and regulatory bodies to adopt the definitions set out in the Distribution Reliability Measures Guideline when undertaking reporting, bench-marking and managing incentive schemes.

Finally we suggest that the AER, and the relevant jurisdictional standard setters and regulatory bodies, provide reasons if they deviate from the definitions contained in the Distribution Reliability Measures Guideline. This would provide greater certainty to stakeholders as well as transparency and consistency in the application of distribution reliability measures.

97 The AER's obligations in respect of preparing network service provider performance reports are set out in section 28V of the National Electricity Law (which forms a schedule to the National Electricity (South Australia) Act 1996).

98 The obligations on the AER in relation to the Annual Benchmarking Report are contained in rule 6.27 of the NER.

A Members of the advisory stakeholder working group

Representative	Stakeholder
Lynne Gallagher	Energy Networks Association
Grant Cox	SA Power Networks
Kelvin Gebert	SP AusNet
Steve McHardy	Ausgrid and Networks NSW
Keegan Oliver	Ergon Energy
Craig Savage	United Energy
Ewan Sherman	Aurora Energy
Wayne Ward	Powercor and CitiPower
Paul Dunn	Australian Energy Regulator
John Skinner	Australian Energy Regulator

B Common definitions for distribution reliability measures

This Appendix B contains the recommend 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 this Appendix B.

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*.[99]

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*.[100]

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*.

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

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

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

- 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.[101]

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* reports 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*.[102]

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

101 Indices are calculated on whichever reporting period is required.

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

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 restored for any duration

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 electrical 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, rules 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* is taken to be the end of the *Sustained Interruption*.

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 maximum demand (which can be weather normalised) 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 or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of, the *network* did not cause, in whole or part, the event giving rise to the direction.