Explanatory statement

Final decision

Amendment to the Service Target Performance Incentive Scheme (STPIS)

Establishing a new Distribution Reliability Measures Guideline (DRMG)

November 2018

AUSTRALIAN ENERGY REGULATOR

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1 Overview

The AER is responsible for the economic regulation of electricity distribution networks in all Australian jurisdictions except Western Australia, in accordance with the National Electricity Rules (NER).

Under chapter 6 of the NER, we are required to publish, administer and maintain:

- a Distribution Reliability Measures Guideline (DRMG) which specifies a set of common definitions and parameters to assess and compare the reliability performance of distributors
- a Service Target Performance Incentive Scheme (STPIS) in accordance with rule 6.6.2 of the NER which provides incentives for maintaining and improving performance of distributors to the extent that customers are willing to pay for such improvements.

1.1 Background to this review

In 2016 the AEMC reviewed the framework for measuring reliability performance and observed inconsistencies in measuring reliability across the National Electricity Market (NEM), partly due to jurisdictional definitions.[1] The AEMC's review resulted in a rule change that required us to publish the DRMG.

The AEMC proposed a number of major changes to the current measurement method. These included changing the definition of momentary interruption from less than 1 minute to less than 3 minutes. This recommendation was made to provide additional incentives for distributors to invest in more automation infrastructure to improve supply reliability.

These changes result in altering the measurement method for the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).[2] Since SAIDI and SAIFI are the key reliability components of STPIS, we must also amend the STPIS to be consistent with the revised measurement.

The STPIS that applies to electricity distribution networks has not been reviewed since 2009. We have taken the opportunity to review the results of the STPIS. We have observed that, because of the incentive structure of the STPIS, distributors have focused on reducing the number of short interruptions to the customers' power supply, rather than also reducing the number of long interruptions. As a result, the average

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1 AEMC, *Review of Distribution Reliability Measures, Final Report,* 5 September 2014.

2 Unplanned SAIDI refers to the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less). Unplanned SAIFI refers to the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

length of interruptions has increased. We consider that customers, while satisfied with the reduction in the number of short interruptions, also wish to avoid long interruptions. We have therefore made an adjustment to the STPIS formula to better balance the weights given to the frequency and duration of interruptions.

1.2 Key amendments to the STPIS

Our key amendments to the STPIS are as follows:

- We will change the weighting ratio for the STPIS incentive rates from the existing “50% SAIFI / 50% SAIDI” to “40% SAIFI / 60% SAIDI”.
- We will simplify the scheme by specifying STPIS outcomes as a fixed monetary amount, rather than as a percentage adjustment to the maximum allowable revenue (MAR).

We have made further amendments to the STPIS following our consultations with stakeholders to:

- improve the clarity, effectiveness and operation of the scheme
- simplify the current approach for the s-factor calculations
- align the scheme with other changes proposed for the DRMG.

1.3 Key considerations for the DRMG

Our final decision is to implement the AEMC's recommended definitions for all key distribution reliability measures. However, we have not accepted their proposed method to identify the Major Event Days (MED) that were excluded from the performance measures data set.

We will also implement the AEMC's recommendation to change the threshold for momentary interruptions and momentary interruption events from less than 1 minute to less than 3 minutes. This change will encourage investment in automation facilities to restore supply more quickly after a network fault.

1.4 Implementation of the amended STPIS and DRMG

This final decision sets out the reasons for the new DRMG and the amendments to the STPIS, and discusses our consideration of submissions received from stakeholders.

As identified in the relevant Framework and Approach statements, we will apply the revised STPIS in the distribution determinations for South Australia and Queensland and those following.[3]

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3 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/energex-determination-2020-25/aer-position; https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/aer-position

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAIDI	Customer Average Interruption Duration Index
distributor	distribution network service provider
ENA	Energy Networks Australia
DNSP	distribution network service provider
DRMG	distribution reliability measures guideline
MAIFI	momentary average interruption frequency index
MAIFIe	momentary average interruption frequency index event
NEL	national electricity law
NER	national electricity rules
RIN	regulatory information notice
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
VCR	value of customer reliability

2 Key issues

2.1 The STPIS

The STPIS is intended to ensure that distributors do not reduce their service levels as a result of their efforts to improve efficiency which typically are associated with a reduction in expenditure. It encourages distributors to improve service reliability but only where customers are willing to pay for these improvements.

The STPIS rewards distributors where they exceed their reliability targets, and penalises them when they allow power supply to fall below the reliability targets. The reliability targets are typically based on the level of reliability achieved by a distributor over a recent period. The targets are typically amended for each distributor every five years as part of the regulatory determination process to take account of the most recent reliability performance of the distributor.

Distributors will receive a financial reward only if they improve reliability. They will only be able to retain the reward if they maintain the reliability improvement. Once an improvement is made, the performance targets will be tightened for future years to reflect the improved level of performance. If the higher level of reliability is not maintained, or if reliability decreases for any other reason, a penalty is payable. A financial reward for improved customer reliability is paid by customers while penalties to distributor for a reduction in reliability performance mean customers get a price reduction.

2.2 Reliability in the STPIS

The power supply is highly reliable. However, interruptions cause loss and inconvenience to customers.

There are two important aspects of reliability – the frequency of interruptions and the duration of interruptions.

The frequency of interruptions is typically measured by the System Average Interruption Frequency Index or SAIFI. SAIFI is calculated by adding the number of unplanned sustained customer interruptions and dividing this total by the number of customers. It measures the number of interruptions a customer experiences on average.

The duration of interruptions is measured by the System Average Interruption Duration Index or SAIDI. The SAIDI is calculated by adding the duration of each sustained customer interruption in a period and dividing it by the number of customers. It measures the total duration of outages that the customer is likely to experience on average.

Both SAIFI and SAIDI exclude momentary interruptions.

Another important measure is the Customer Average Interruption Duration Index or CAIDI. CAIDI is calculated by dividing SAIDI by SAIFI. It measures the average duration of those interruptions that occur. Another way of thinking about CAIDI is that it measures the average time taken to restore power after an interruption has occurred.

2.3 Incentive rates in the STPIS

The STPIS includes incentive rates to determine how much performance above the reliability targets is rewarded, and how much performance below the target levels is penalised. This is done by taking account of the value that customers place on improved reliability. Because there are two parameters (SAIFI and SAIDI), incentive rates have to be calculated for each. This is done by a formula that gives approximately 50% weight to SAIFI and 50% weight to SAIDI.

We consider that, in practice, this formula has had some undesirable effects. This issue is discussed in some detail in section 4. However, in summary, it has led to an increase in CAIDI, or the average restoration time following an interruption. This suggests that distributors have reduced interruptions of short duration by more than those of longer duration. We think that customers are concerned about long interruptions and would like to encourage distributors to reduce the number of long interruptions. In addition, there is an equity aspect to this. Customers at the further end of feeders are most likely to have long interruptions (because of the length of time it takes for maintenance crews to serve them). They may be disproportionately disadvantaged by a STPIS that excessively rewards reducing short interruptions.

We have therefore proposed a change in the incentive rates to 40% SAIFI and 60% SAIDI. This will reward the reduction of interruptions of long duration and lead to a more balanced outcome.

2.4 Momentary and sustained interruptions

Momentary interruptions involve the brief loss of electricity supply and are the result of reclosing circuit breakers opening and then reclosing after a short delay to clear non-permanent faults. Sustained interruptions require the distributor to intervene to restore power. Sustained interruptions are typically caused by lightning strikes, trees striking power lines and equipment failures. The impact of a sustained interruption on customers is usually significantly greater than a momentary interruption because of the longer duration.

There are two relevant measures of momentary interruptions. The first is the Momentary Average Frequency Index or MAIFI. This is calculated by adding the number of interruptions of a momentary nature that are experienced by a group of customers and dividing the total by the number of customers.

The second measure is the Momentary Average Frequency Interruption Index event or MAIFIe. A momentary interruption event is an event during which a distributor makes single or multiple attempts to restore supply through the use of an auto-recloser. Where this is more than one restoration event during an incident, this incident is calculated as one event. MAIFIe is calculated by dividing the number of Momentary Interruption Events by the number of customers.

As noted, the AEMC recommended a number of changes to the measurement of reliability in 2014. The most important of these is a change in the threshold for defining momentary interruptions from less than one minute to less than three minutes. We have decided to implement this recommendation.

3 The AER's review

We have undertaken three rounds of consultations with stakeholders in reviewing the STPIS and establishing the DRMG.

The issues paper

Since the review of STPIS and establishment of the DRMG are closely interrelated, we published an issues paper on both topics on 5 January 2017. The issues paper sought stakeholders' feedback on issues relating to the performance of STPIS and outlined our position on uniform reliability measures across all jurisdictions.

Draft Distribution Reliability Measures Guideline

After considering stakeholders' submissions to the issues paper, we published a draft DRMG for consultation on 23 June 2017.

Draft STPIS modifications

After considering stakeholders' submissions to the issues paper and the draft DRMG, we published a draft of a revised STPIS for consultation on 14 December 2017.

This explanatory statement

This paper sets out our final decisions, explains the reasons for them and responds to the submissions we have received on the draft DRMG and revisions to STPIS. The rest of this statement is organised as follows:

- Chapter 4: Explains why we have changed the incentive rates on SAIFI and SAIDI
- Chapter 5: Provides the reasons for decisions common to both the DRMG and the STPIS
- Chapter 6: Provides reasons for decisions on matters specific to distribution reliability measures
- Chapter 7: Provides reasons for decisions on matters specific to the STPIS
- Appendices A, B and C: Present our response to submissions from stakeholders
- Appendices D and E: Present technical models and equations.

4 SAIFI/SAIDI incentive rate weighting ratio

4.1 Draft decision

In our draft report, we noted that, while the frequency of supply interruption is reducing, the average supply restoration time (CAIDI) is getting longer. We suggested that the network businesses may be emphasising capital expenditure to reduce the frequency of interruptions rather than the operating expenditure that is often required to improve the time taken to repair faults.

We noted a further problem with the existing STPIS design. The incentive rate for SAIFI is set on the basis of the CAIDI of the previous five years. Based on our observation, the networks appear to respond to the incentives in the STPIS in a way that the improvements in SAIFI are higher than that for SAIDI in percentage terms, resulting in higher CAIDI (restoration time). This higher value of CAIDI will then enter into the incentive rates formula, further increasing the incentives to improve SAIFI relative to SAIDI. This creates a feedback loop with a subsequent effect of yet an even higher CAIDI and further increases in incentives to improve SAIFI relative to SAIDI and so on.

We noted that there are two possible options to manage the feedback effect:

- to fix the CAIDI value in the incentive rate calculation formula as suggested by Endeavour Energy in its submission to the issues paper
- to rebalance the incentive weighting for SAIDI and SAIFI in the formula.

In the draft decision we proposed to adopt the second option by revising the weighting from 50% SAIFI / 50% SAIDI to 40% SAIFI / 60% SAIDI. The first option is very difficult to implement. We cannot be confident that either the current year CAIDI value or the historical average CAIDI value would represent a suitably balanced ratio. We therefore suggested that the weighting ratio should be changed to 40% SAIFI / 60% SAIFI.

4.2 Submissions

We received a number of submissions from stakeholders on this issue, including from the Public Interest Advocacy Centre (PIAC), electricity distributors, the Independent Pricing and Regulatory Tribunal (IPART) and the S&C Electric Company:

- PIAC supported the revision to the SAIDI/SAIFI incentive weighting ratio to 40% SAIFI / 60% SAIDI to remove the bias towards preferring expensive SAIFI-related network augmentation over SAIDI-improving opex.
- S&C Electric Company (an electrical equipment manufacturer) argued that OFGEM has a similar scheme to STPIS, with a weighting approach that gives less weight to SAIFI improvements than SAIDI improvements. They added:

> It is preferable to incentivise each performance metric to deliver the desired outcomes rather than rebalancing the ratio, which has unintended consequences.

> Its analysis suggests that a similar scheme by OFGEM has a weighting factor between 65-85 per cent on the SAIFI incentive.[4]
>
> Based on its analysis, the OFGEM supply interruptions incentives places a higher proportion of incentive value on SAIDI than the 60:40 suggested by AER and has worked well in driving both SAIFI and SAIDI down—The OFGEM scheme achieved a 51 per cent improvement in SAIFI and 49 per cent improvement in SAIDI, with only an one per cent deterioration in CAIDI.

- Jemena supported the proposed change to the SAIFI/SAIDI ratio. Ausgrid offered conditional support and proposed that the incentive weighting should be applied flexibly depending on each distributor's circumstances.
- Other distributors and Energy Networks Australia (ENA) objected to the proposed adjustment to the SAIFI/SAIDI weighting ratio because they considered the AER’s proposal had not been based on sufficient analysis and said that a cost-benefit analysis should be used to identify a suitable incentive ratio.

A summary of the submissions received and our response to the submissions can be found in Appendix A.

4.3 Reasons for our final decision

We consider that the current STPIS excessively rewards reduction in SAIFI over reduction in SAIDI. For example, for United Energy the current reward for reducing SAIFI by one event equals 68 minutes in SAIDI reduction.

In the Issues Paper and the draft decision on STPIS, we noted that CAIDI has increased in all jurisdictions under the current STPIS, which commenced operation in 2011. A similar scheme has been in operation in Victoria since 2006. The results are presented in Appendix B. These show that average CAIDI has increased:

- from 65 to 75 minutes from the previous regulatory control period to the current period; and
- by an average of 30 per cent increase in the 10 years since the scheme was introduced in Victoria.

In Appendix B, we provide an example that shows that distributors can get a reward under the current STPIS if the average duration of interruptions doubles provided that the number of interruptions reduces by one third. As noted in Attachment A, evidence from AEMO's 2014 VCR studies suggests that residential customers are particularly concerned to avoid long interruptions. This indicates that the increasing CAIDI (average restoration time) under the current scheme is concerning. Examples provided by AusNet Services and SA Power Networks in their submissions in response to the

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4 OFGEM’s framework includes both planned and unplanned outages. Comparison of the AER’s proposal with OFGEM’s scheme needs to be done on a like for like basis, rather than the total incentive weighting of OFGEM.

draft determination clearly suggest the current scheme has resulted in an increasing CAIDI and an increase in average restoration time after allowing for the effect of a change from manual switches to auto reclosers.

We consider that we have enough evidence to make this change at this time. However, the AER is to commence work to review the Value of Customer Reliability to customers. Once the results of this work are available, we will consider whether further changes to STPIS are needed.

4.4 Analysis of CAIDI increases

We consider that CAIDI (average restoration time) is increasing because the percentage improvement in SAIFI (frequency of outages) is greater than the percentage improvement in SAIDI (duration of outages).[5] Because the SAIFI incentive rate is based on the CAIDI result of the previous regulatory period, there is a feedback effect.

In the draft decision we agreed that:

1. The time taken to repair faults largely depends on operating expenditure since it involves the deployment of field crews to attend faults.
2. The reduction of SAIFI largely involves capital expenditure since most SAIFI reductions have been achieved through automation such as auto-reclosers.

In the draft decision, we proposed to reduce the incentive rate from 50% SAIFI / 50% SAIDI to 40% SAIFI / 60% SAIDI.

As noted, the consumer group, PIAC, supported the proposed change because it would tend to reduce capital expenditure and hence additions to the regulatory asset base.

However, all but one distributor disagreed with the change because:

- the proposed change is inconsistent with what the distributors consider to be customers' preference for fewer interruptions
- our worked example in the draft decision to demonstrate the effect of the proposed change was incomplete. This is because we did not consider the effect of replacing existing manual switches with auto-reclosers, which has the effect of increasing the CAIDI measure even if the fault repair time does not change.[6]

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[5] AER, *Issues paper, Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guidelines, Electricity distribution network service providers*, January 2017, pp. 14-17; AER, *Explanatory statement, Proposed amendment Service Target Performance Incentive Scheme (STPIS),* December 2017, pp. 13-16.

[6] Because supply to the customers on the source side of the manual switch will be restored as soon as the fault location is identified, by isolating the fault zone by opening the manual switch.

We have considered these issues further and our analysis is set out in Attachments A and B. We have reached the following conclusions:

- The high SAIFI incentive rate currently in the STPIS means that, after investments to reduce SAIFI, distributors can still receive rewards even if supply restoration time deteriorates significantly.
- The proposed 40% SAIFI / 60% SAIDI ratio would result in more balanced incentives for SAIFI and SAIDI outcomes, as was the original intention of the scheme.
- The unbalanced incentive rates are likely to have resulted in encouraging more weight on capital expenditure rather than operating expenditure. Five distributors agreed that this is the expected result of the current approach.
- AusNet Services' and SAPN's submissions indicate that their action of replacing manually operated switches with auto-reclosers will result in an increase in CAIDI. However, there has been an increase in CAIDI even allowing for the effect on CAIDI of replacing manually operated switches by auto-reclosers.
- The 3-minute MAIFI threshold (which is part of the new reliability measures guideline) will provide greater incentives for capex solutions, because it will encourage the introduction of distribution automation systems.[7] The greater use of automation systems is desirable but would require more capital expenditure. This additional incentive emphasises the importance of correcting the already high incentives to invest in capital expenditure under the existing 50% SAIFI / 50% SAIDI incentive weighting.

4.5 Final decision

We will implement a change from the existing 50% SAIFI / 50% SAIDI incentive weighting rate to 40% SAIFI / 60% SAIDI. This is because:

- The existing 50:50 incentive rate weighting ratio has resulted in SAIFI consistently improving faster than SAIDI. Distributors have placed greater emphasis on reducing the occurrence of short rather than long interruptions.
- Based on the most up-to-date VCR research findings, we consider that most customers wish to avoid long interruptions. However, the current incentive ratios appear not to sufficiently incentivise businesses to reduce long interruptions.[8]
- The current incentive rates are not well balanced. We have sufficient information to make a significant but not large change to the current incentive weights.

A similar arrangement that favours SAIFI less than SAIDI is already in operation in the UK and has had the desired effect in encouraging more balanced outcomes.

[7] AEMC, *Review of Distribution Reliability Measures, Final Report,* 5 September 2014, p. 15.

[8] Following a recent AEMC rule change, we will undertake a new VCR survey shortly.

5 Matters common to DRMG and STPIS

5.1 Changing the definition of a momentary interruption

In its review of distribution reliability measures, the AEMC recommended a change to the definition of a momentary interruption from the current threshold level of less than 1 minute to less than 3 minutes. The AEMC stated that this change would make it easier for distributors to reduce their costs by introducing distribution automation systems.[9]

In the draft decision, we supported the AEMC's recommendation to change the definition of a momentary interruption. This is because this change will encourage investment in automation facilities to restore supply more quickly after a network fault.[10]

5.1.1 Submissions

The submissions from distributors[11] and from ENA in response to our issues paper all supported the change to a less than 3 minute threshold for defining a momentary interruption.

S&C Electric Company submitted that this change could have potential negative effects on industry and commercial customers.

Effects on industrial and commercial customers

S&C Electric Company's submission argued that moving to a less than 3 minutes threshold would impose additional costs on industrial and commercial customers and distributed generation. They also claimed increasing the threshold for a momentary interruption to 3 minutes would affect SAIFI performance because the incentive for distributors to improve reliability would be reduced.[12]

The key purpose of this change is to make it easier for distributors to implement network automation. This will enable distributors to restore supply quickly by converting some longer outages into short term momentary outages.

This approach should benefit all customers, including industrial and commercial customers. The change in the threshold in the definition of a momentary outage does

9 AEMC, *Review of Distribution Reliability Measures*, *Final Report*, 5 September 2014, pp. i-ii.

10 AEMC, *Review of Distribution Reliability Measures*, *Final Report*, 5 September 2014, p. ii.

11 The distributor submissions were from CitiPower, Powercor, Endeavour Energy, Energex, Ergon, Essential Energy, Jemena, and SA Power Network in response to our draft decision on DRMG.

12 S&C Electric Company, *Submission to the Proposed Amendment to the Service Target Performance Incentive Scheme (December 2017)*, 9 February 2018, pp. 3–4.

not mean that those outages where supply can currently be restored within one minute will, following the changes, be delayed by two minutes more.

More importantly, as identified by AEMC, it is not economically feasible or even possible to eliminate all interruptions. All network users need to take precautions against unplanned supply interruptions, including momentary interruptions.[13]

Conclusion

We confirm our decision to move to a 3 minute threshold for the definition of a momentary interruption. To ensure that consistent data are used, we require distributors to remove data on interruptions of less than 3 minutes from their historical data sets.

5.2 The use of MAIFI and MAIFIe

STPIS currently uses MAIFI to measure momentary interruptions. This is defined as the total number of customer interruptions of one minute or less, divided by the total number of distribution customers.

The alternative measure is "momentary average interruption frequency index event", or MAIFIe. This measures the total number of momentary interruption events, where a momentary interruption event is one or more momentary interruptions within quick succession.

Currently only Victorian distributors have adequate monitoring equipment to accurately report momentary interruptions. Hence, they are the only distributors subject to the MAIFI measure under STPIS. Due to historical practice, MAIFIe is still being used instead of MAIFI for most of the Victorian distributors under STPIS.

We agree with the AEMC's recommendation that MAIFIe is a more suitable measure. This is because it is more reflective of the customers' experience in terms of availability of supply. Consequently, we consider that MAIFIe should be applied where distributors are able to capture this data. MAIFI will be applied where distributors are unable to capture MAIFIe data due to measurement difficulties.

5.2.1 Submissions

Essential Energy supported the use of MAIFIe but stated that it currently is not able to collect this information.

Likewise, Energex and Ergon Energy also supported the use of MAIFIe. They are in the process of establishing the capability to record and report the data.[14]

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13 AEMC, *Review of Distribution Reliability Measures, Final Report*, 5 September 2014, p.14.

14 Essential Energy, *Submission on the Draft Distribution Reliability Measures Guidelines*, August 2017, p. 2; Energex and Ergon Energy, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 5.

5.2.2 Final decision

We consider that the use of MAIFIe is preferable for reporting purposes and for use in our STPIS. This said, we recognise that some distributors are unable to provide MAIFIe data without significant investment to capture this data.[15]

Consequently, we consider that MAIFIe should be applied where distributors are able to capture this data. But, MAIFI can be applied where distributors are unable to capture MAIFIe data.

5.3 Broadening exclusion conditions

This section discusses the treatment of exclusions and major event days when calculating distribution reliability measures.

The STPIS allows the removal of some types of interruptions from the reliability data set. These interruptions are removed either because they are beyond the control of the distributors (exclusions) or because they are not representative of a normal day in terms of reasonable network resource availability, known as a Major Event Day (MED).[16]

5.3.1 Additional exclusions recommended by the AEMC

In our draft decision we endorsed the AEMC's recommendation to add a new exclusion criterion:[17]

> 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

Such interruptions are beyond the control of distributors.

5.3.1.1 Submissions

In their submissions, Ergon Energy and Energex proposed also to exclude interruptions caused by failure of electrical installations that are owned by customers.

5.3.1.2 Our assessment

There are two possible scenarios resulting from a failure of a customer's electrical installation:

- The distributor's network is still intact despite the failure of the customer's equipment. Hence, only the specific customer's electricity supply is not available

15 Essential Energy, *Submission on the Draft Distribution Reliability Measures Guidelines*, August 2017, p. 2.

16 Major event days are typically caused by severe weather conditions.

17 AEMC, *Review of Distribution Reliability Measures, Final Report,* 5 September 2014, p. 22.

due to automatic protection equipment or as the result of a malfunction of the customer's installation.

- The distributor's network is affected by the customer's equipment failure, resulting in other customers also being without supply.

Under the first scenario, there is no loss of supply to other customers. Hence, there is no need to exclude the event when calculating reliability measures.

Under the second scenario, there is a loss of supply to other customers. The distribution network can install protection equipment to safeguard its own network and protect other network users. These interruptions are therefore capable of being controlled by distributors.

5.3.1.3 Final decision

We will exclude interruptions caused or extended by a direction from state or federal emergency services from reliability data sets, provided that the fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction. We will not exclude interruptions caused by failure in electrical installations by customers.

5.3.2 Outage of transmission connection assets due to the actions of a distributor

In the issues paper and the draft decision, we argued that the current criterion for excluding outages that result from failure of transmission connection assets needs greater clarity to be made more effective. At present, the criterion only includes conditions where the distributor is responsible for planning transmission connections.

5.3.2.1 Issue

We consider that distributors' control over the correct operation of transmission connection assets extends beyond the planning function. For example, we are aware of an incident where a distributor failed to follow well-established network operation procedures. This resulted in the triggering of a protection relay which caused a transmission connection transformer and a number of high voltage feeders to shut down. Hence, we proposed to add a further test to ensure that only outages which are not due to an act or omission by the distributor are excluded.

5.3.2.2 Submissions

Submissions from ENA and distributors accepted the principle that distributors should not be permitted to exclude a transmission outage event if the event is caused by the action or inaction of that distributor. However, they considered that a clear approach to defining the “primary cause” should be established to avoid lengthy dispute resolution processes.[18]

5.3.2.3 Final decision

We consider that the distributor and the auditor who reviews the annual regulatory information notice (RIN) will be able to determine whether an outage is due to the inappropriate actions or inactions of the distributor that are inconsistent with good industry practice. We therefore consider that only outages where the distributor has adequately planned for the necessary power transfer capacity of transmission connection assets and are not due to the inappropriate actions or inactions of the distributor should be excluded from the data set.

5.3.3 Additional exclusion of catastrophic events in addition to the current major event days exclusions

Major Event Days exclusions under the STPIS use a statistical formula to calculate a threshold value. Where the SAIDI value of a particular day (the daily SAIDI) exceeds this threshold value, it is considered to be a MED. The performance data for all MEDs are reported by the distributors. These data are not counted towards the calculation for the reward/penalty under the STPIS incentive framework.

The AEMC noted that:[19]

- 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 reliability measures. Such events include (1) 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; (2) a requirement to comply with jurisdictional regulations; and (3) acting under a direction from state or federal emergency services.
- Generally, catastrophic events and 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.

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18 ENA, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 2; CitiPower and Powercor, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 2; Energex and Ergon Energy, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 5; Essential Energy, *Essential Energy Submission on the Draft Distribution Reliability Measures Guidelines*, 7 August 2017, p. 1; SA Power Networks, *Draft Decision, Draft Distribution Reliability Measures Guidelines*, 11 August 2017, pp. 3–4.

19 AEMC, *Review of Distribution Reliability Measures, Final Report,* 5 September 2014, section 4.

- Even though the interruptions that occur on MEDs 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.

The AEMC's observations and recommendations are similar to the current STPIS exclusion framework. However, they also recommended that we should consider first excluding catastrophic events such as major bush fires, cyclones and floods from the data set before considering the threshold for defining MEDs.

5.3.3.1 Draft decision

In our draft decision,[20] we proposed not to exclude catastrophic events before applying the standard 2.5 beta (2.5 standard deviations) method[21] to identify the threshold for major events. We considered that:

- There is no current objective or definitive method to identify catastrophic events as outlined by the AEMC.
- There are material differences between networks in Australia, ranging from localised urban networks (such as CitiPower) to physically diverse and geographically large networks (such as SA Power Networks and Ergon Energy). A definition of catastrophic events and their measurement methods are unlikely to be uniform across all distributors.

5.3.3.2 Submissions

We received a number of submissions on this issue. IPART supported our recommendation and agreed with our concerns on this matter. It further commented that (1) removal of catastrophic events before applying the IEEE 2.5 beta method would only increase the number of excluded days in a way not intended by the IEEE standard; and (2) such an approach is not fair to the customers in cost/benefit terms.

PIAC submitted that, while there is no consistent method to identify catastrophic days, the AER should exclude such events because they are outside of the control of a distributor, infrequent and, over the long term, unpredictable in terms of the location and nature of impact.

Essential Energy argued that the AEMC’s recommendation should not be ignored just because a clear identification method is absent. It submitted that the AER should adopt a 4.15 beta method or a geographical area based method in the interim.

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20 AER, *Explanatory statement to draft distribution reliability measures guidelines*, June 2017, pp. 14–15.

21 The methodology used in STPIS to identify major events days is based on the Institute for Electrical and Electronic Engineers (IEEE) Standards1366, called the 2.5 beta method. This method transforms daily unplanned SAIDI data through a natural log application in order to make the data set resemble a “normal distribution”.

SA Power Networks argued that we were inconsistent in arguing that there should be an objective method to identify major event days because we had previously allowed a higher than 2.5 beta threshold level to set the threshold for major event days.

5.3.3.3 Our assessment

There are two issues related to the treatment of catastrophic events:

- consistent measurement of supply reliability across all jurisdictions
- defining the coverage areas of STPIS (relating to rewards and penalties under the scheme) of each distributor.

SA Power Networks' contention conflated the two applications. It correctly pointed out that the current STPIS does have flexibility for distributors to have a higher threshold of the major event day (MED) boundary. This would reduce the number of exclusion days in a year—or, increase the level of accountability of the distributor who opts for a higher MED boundary. Whereas, the purpose of the DRMG is to establish a consistent measurement method for supply reliability.

The flexibility provision under the STPIS to set the threshold for major event days will still be available for distributors to make adjustments to meet customers' expectations.

5.3.3.4 Final decision

If we cannot identify a consistent measurement approach for the definition of a catastrophic event using multiple beta thresholds, as defined by the IEEE standard, we cannot simply adopt an arbitrary number. Hence, we will retain the current approach of using a 2.5 beta standard to define major events days without prior exclusion of catastrophic events. We require a uniform method that can be applied to all distributors consistently.

5.4 Broadening the definition of urban feeders

When measuring distribution reliability, it is common to distinguish between different parts of a distribution network by classifying the feeders. The AER and most jurisdictions currently classify feeders as CBD, urban, short rural and long rural feeders.

In our draft determination we defined an urban feeder as one that exceeded a threshold value of 0.3 MVA/km on average over a three year period.

5.4.1 Submissions

CitiPower and Powercor proposed a further refinement to the definition. This is to consider circumstances where there are significant changes in feeder length, for example as a result of network reconfiguration such as the establishment of a new zone substation.

Endeavour Energy stated that it should be given the flexibility to manually allocate a particular feeder to a classification.[22]

5.4.2 Our assessment

We acknowledge that feeder lengths may change significantly because of network reconfiguration. Hence, the average feeder length over a three year period would be preferable.

We consider that feeders should be classified based on the actual load density rather than based on the forecast future load density, which may or may not eventuate.

The purpose of having common definitions is to provide certainty and consistency for reporting purposes and to limit gaming. As such, we consider that distributors should not be able to reallocate feeders to classifications. That said, distributors may reclassify feeders during the revenue determination process.

5.4.3 Final decision

We will establish a threshold for the definition of an urban feeder based on average demand over a three year period and over the average length of that feeder for the period.

5.5 Supply outages due to malfunction of energy meters

We sought advice from distributors on whether they currently report supply outages due to malfunction of standard energy meters they provide to typical customers.[23] The responses were mixed because some distributors did not classify meter malfunctions as outages. In December 2017, meter services became contestable, thereby further complicating the reporting of these malfunctions because retailers are now responsible for the correct functioning of meters.

Due to practical considerations, energy meters are not placed at the point of supply. Distributors' points of supply to customers are:

- for overhead services, at the junction boxes at the eaves
- for underground services, at the service pit just outside the front fence.

Energy meters are installed inside the metering cubicles located between the point of supply and the customers' main switch boards. Hence, technically speaking, supply

[22] Endeavour Energy, *AER Draft Distribution Reliability Measures Guidelines*, 11 August 2017, pp. 1–2.

[23] Types 5 and 6 meters under chapter 7 of the NER.

losses to a customer's installation due to malfunction of energy meters are not supply outages, because there still is power available at the point of supply.

We therefore proposed in our draft determination to exclude supply outages due to malfunction of energy meters from the reliability data set.

5.5.1 Submissions

Ergon Energy and Energex supported our proposal to exclude interruptions associated with meter malfunctions.[24]

5.5.2 Our assessment

Since December 2017, the responsibility for metering installation resides with energy retailers or metering co-ordinators. We therefore consider that supply outages due to meter malfunctions should be excluded from the definition of "outage" in the DRMG. Hence, the definition of supply interruption should be measured at the point of supply.

5.5.3 Final decision

We will exclude interruptions associated with meter malfunctions from the reliability data set.

5.6 Improving consistency of measurement methods

In its final report reviewing distribution reliability measures, the AEMC noted that the capturing and reporting of electrical interruption data vary across the NEM to reflect the systems and processes of the different distributors.[25]

Previous reports have identified significant variations in the accuracy of the reliability information across distributors. These potential variations have historically been assessed between +5% and -20% of the reported data.[26] Improvements in information systems, data capture and smart metering will have improved these error rates.

The STPIS definition for unplanned SAIDI is:

> The sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions.

Currently, this definition is further clarified by a number of notes:

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[24] Energex and Ergon Energy, *Draft Service Target Performance Incentive Scheme (STPIS)*, 11 August 2017, p. 7.

[25] AEMC, *Review of Distribution Reliability Measures, Final Report*, 5 September 2014, p. 19.

[26] PB Associates, *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability Prepared for IPART*, 2003.

1. The number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period.

2. Unmetered street lighting supplies are excluded. Other unmetered supplies can either be included or excluded from the calculation of reliability measures.

3. Inactive accounts are excluded.

4. In calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Sustained interruptions which occur when a recloser locks out after several attempts to reclose should be deleted from MAIFI calculations.

The capture of reliability statistics is essentially a process of linking a network outage incident to the customers interrupted by the incident. As an incident (e.g. resulting from a short circuit fault) may occur on any part of the network, it is necessary to create a link that is representative of the connectivity of the network in terms of fault location, associated network outage, and customers interrupted (affected) due to the network outage.

The availability of connectivity data (the smallest network segment that customers are generally allocated to) varies between each distributor and typically ranges between the feeder circuit breaker and the distribution substation. Some distributors have historically used postcode averaging.

The greatest accuracy from a reliability measurement system will be gained from a system that links the customer at the lowest possible level. If a distributor maintains connectivity data at the distribution substation level, this means that the collection of data below this level must come from approximations and manual intervention.

In general, the greater the degree of approximation and manual intervention, the more inaccurate the resulting information will be. As the connectivity level information used by a distributor could impact the rewards or penalties under STPIS, there may be a need to better understand or audit this information.

5.6.1 Draft decision

In our draft determination, we noted that the systems and processes that distributors use to capture interruption data vary across the NEM. We proposed a number of measures to improve the standardisation of reporting — in particular, regarding the treatment of single phase outages and single premises outages.

5.6.2 Submissions

Ergon Energy and Energex generally supported standardisation of reporting.[27] They suggested that data systems would need to be upgraded to report the data. There could therefore be a delay before more accurate data could be reported.

5.6.3 Final decision

In addition to the current reporting, the following additional reporting arrangements are to be included in the DRMG. This will provide greater clarity on the extent to which specific events have been captured or reported in the data.

- National Metering Identifiers—the following NMI codes should be reported: active, not energised, extinct, greenfield.
- Single premises outages—single premises interruptions should be reported as a network interruption unless the customer's fault is actively identified.
- Where more accurate information from smart meters is absent, incidents should be reported as a partial network failure.
- The reporting of HV single phase outages on a three phase network should be standardised to be 67% of downstream customers. The reporting of all other HV outages should be standardised at 100% of downstream customers. This includes, for example, single phase HV outages on a two phase or single phase HV system.
- The reporting of LV single phase outages should be standardised to be 33% of all downstream customers affected by the outage.

5.7 Capping guaranteed service level (GSL) payments

Ergon Energy and Energex submitted that the STPIS GSL payments scheme goes beyond existing jurisdictional GSL arrangements (in Queensland), which does not set GSLs for the total duration of interruptions. They recommended that a cap should be set for the total GSL payments for individual customers across all elements of GSL payments, similar to the current $454 per annum cap set by the Queensland Competition Authority.

5.7.1 Our assessment

We consider that, because the s-factor part of the STPIS is measured in terms of network average outcomes, there will always be some consumers at remote ends of the network who experience supply reliability that is substantially below the average for the network. GSL payments are designed to provide compensation to these consumers.

We also note that:

- The current GSL scheme already has a cap on the maximum amount that can be paid for all interruptions of supply—60 hours in a year.
- The GSL payments incurred by distributors do not represent a significant proportion of their expenditure in a year.

There are no corresponding limits on the calculation of the s-factor outcomes for the total frequency of supply interruptions.

If a distributor is subject to a jurisdictional scheme, the GSL element under STPIS will not apply.

We do not consider that a strong argument has been made to cap the GSL payments that can be received by a customer.

5.7.2 Final decision

Our final decision is not to cap the GSL payments.

5.8 Implementation and reporting

The DRMG is the means to implement standardisation of reporting. However, to operationalise the DRMG, we need to modify our RIN instructions for each distributor for reporting purposes.

Hence, the earliest stage that we may implement and apply these distribution reliability measures is when we issue the new RINs for the next regulatory control period for individual distributors. The distributor will need to implement reliable data management systems to collect new data and make them available to us.

6 Matters specific to distribution reliability measures guideline

This section sets out our consideration on matters specific to the distribution reliability measures guideline.

6.1 Treatment of unmetered supply

The STPIS currently allows distributors to decide whether to include unmetered loads in calculating the SAIFI, SAIDI and MAIFI performance measures.[28] Currently, public lighting is excluded from STPIS performance reporting.

6.1.1 Submissions

We received submissions from several NSW councils that argued that unmetered supplies should be included in performance measures. The focus of their submissions was on street lighting and public lighting. They submitted that the performance outcome of such lighting should be measured as part of the distributors' performance indicators. They also outlined that street lighting outages can last for long periods of time and street lighting is held to a substantially lower reliability standard than for all other classes of customers.[29]

6.1.2 Our assessment

We accept the importance of maintaining high reliability standards for street lighting and recognise that long duration public lighting outages are undesirable. However, we consider that including unmetered connections within the supply reliability measures would not address the issues raised by the councils, and would be unlikely to have a material impact on public lighting service standards. This is because:

- It is unlikely that long street light outages are purely due to electricity supply issues. Unless the lighting is supplied by a part of the network without any other metered customers, any long outage will be identified, captured in performance reliability measures and addressed by the relevant distributor. Very long street light outages appear more likely to be the result of maintenance issues rather than due to power supply outages. This includes control gear malfunctioning and lamps not working. The issue of proper maintenance of public lighting is out of scope of the development of the DRMG.

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

29 Central NSW Councils, *Submission*, 10 March 2017; SSROC, *Submission on Service Target Performance Incentive Scheme (STPIS) Review & Distribution Reliability Measures Guidelines*, 23 February 2017; Western Sydney Regional Organisation of Councils, *Email to AER Submission on Service Target Performance Incentive Scheme (STPIS) Review & Distribution Reliability Measures Guidelines*, 10 March 2017; Local Government NSW, *AER review of Service Target Performance Incentive Scheme*, 22 March 2017.

- In NSW, the service standard for public lighting is regulated by the NSW Public Lightning Code. We note that this code has recently been revised to impose greater certainty of obligations and service levels to be provided by the NSW distributors.[30]
- There are not many unmetered connections other than street lights. Including such loads in the overall performance reporting may not provide information on the level of service provided to these connections. For these reasons, it is unlikely that inclusion of unmetered loads within performance reporting will provide useful information on the level of service provided to these connections.

6.1.3 Final decision

We will maintain our draft decision not to include unmetered load for reporting of network reliability measures.

6.2 Adding a reliability measure to identify customers who experience an inadequate level of service reliability

Our draft decision on the DRMG noted that the current reliability measures (used in the STPIS) do not identify customers who experience an inadequate level of service reliability. The AEMC recommended that we monitor and report on the reliability levels faced by these consumers.

The current incentives in the STPIS are based on the average performance results of each type of feeder within the entire network. This measurement method may lead to a focus on reliability supply restoration in the more populated areas. This is because the repair of a network fault in areas with high customer density will result in restoration of supply to more customers than that for a similar fault in much less populated areas. This has the effect of increased STPIS rewards because the SAIDI outcome will be better. As a result, supply restoration times in remote areas may not improve, or may even decline relative to the average restoration time.

Remote areas are generally located at the end of long feeders and on remote parts of the networks. Typically, only limited alternatives are available to provide supplies when faults occur. Customers in remote areas are impacted by all network faults on the full length of the feeders, experiencing more outages than the average customers.

In response to the AEMC's recommendation to monitor and report on the reliability levels faced by customers on the worst performing feeders, our draft decision suggested that customers who experience more than four times the network average level of unplanned SAIDI on a three year average basis are experiencing a

[30] https://energy.nsw.gov.au/government-and-regulation/legislative-and-regulatory-requirements/public-lighting-code

disproportionate level of faults. This customer group is likely to be in the worst 10th percentile of customers by level of reliability.

6.2.1 Submissions and discussion

Essential Energy indicated that it applies SAIFI thresholds at the feeder segment level to capture customers who experience the worst 1 per cent of network reliability levels. It suggested that the AER use this approach to define the customers receiving inadequate level of reliability.[31]

We consider this method would not necessarily identify the customers experiencing inadequate supply reliability. This is because supply interruption events numbers do not represent the total supply interruption durations—as not all interruptions have the same duration.

Distributors and the ENA argued that the definition of customers who experience inadequate reliability should have regard to the current minimum service standards prescribed in the relevant jurisdiction.[32]

The jurisdictional minimum service level standards are typically the minimum service levels that distributors are required to provide. Such levels would not normally represent the threshold to define customers receiving inadequate supply reliability. Where a distributor does not meet such minimum level, it does not necessarily follow that the service level is inadequate by comparison with other similar customers.

Network characteristics in Australia vary greatly, ranging from localised urban networks such as CitiPower, to physically diverse and geographically large networks such as SA Power Networks and Ergon Energy. There cannot be a single threshold SAIDI and SAIFI criterion that can identify who is worst served. The method to identify these customers should be based on a network and locational approach. The definition should also take into account the variation in reliability outcomes from year to year.

CitiPower and Powercor also argued that we should expand the reporting requirements under our annual RIN to include the number of customers affected and list the feeders.

SA Power Networks argued that using the network average for unplanned SAIDI on a three-year rolling average basis may inadvertently capture customers who should not be classified as inadequately served. This is because one very poor SAIDI year may

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31 Essential Energy, Essential Energy, *Submission on the Draft Distribution Reliability Measures Guidelines*, 7 August 2017, p. 2.

32 ENA, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p.3; CitiPower and Powercor, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 3; Energex and Ergon Energy, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 7; Essential Energy, *Essential Energy Submission on the Draft Distribution Reliability Measures Guidelines*, 7 August 2017, p. 2; SA Power Networks, *Draft Decision, Draft Distribution Reliability Measures Guidelines*, 11 August 2017, pp. 4–5; Endeavour Energy, *AER Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 2.

result in the feeder being classified as having an inadequate level of reliability despite the other two years of adequate performance.[33]

However, we consider that the level of service in a year must have been particularly unsatisfactory if it results in the level of SAIDI being above the threshold as “inadequately serviced” on a rolling three year basis. Such situations should be made known to the customers.

Energex and Ergon Energy argued that our use of the terms "disproportionate number of faults" in the draft decision could be taken to mean that SAIFI would also be used as a threshold.[34]

We agree with this submission and clarify that the reporting requirement in this final decision is based on SAIDI results above.

6.2.2 Cost impact of this additional reporting requirement

CitiPower and Powercor argued that reporting on the number of inadequately serviced customers would introduce transactions costs without any commensurate benefit to customers.[35]

We understand that, without further investments in network monitoring, some distributors will not be able to provide detailed locational information on the number of inadequately served customers. Hence, we propose to modify the reporting requirements to enable distributors to report at feeder level where more detailed information is not currently available.

We sought advice from distributors regarding the cost to them of providing the revised reporting. Based on advice from CitiPower, Powercor and United Energy,[36] we consider that the revised reporting arrangement will not have a material cost impact on distributors.

6.2.3 Final decision

Our final decision is to implement the new reporting arrangement to identify customers who experience an inadequate level of reliability. However, we will modify the definition of inadequately served customers to enable distributors to continue using their existing data systems while providing sufficiently detailed information. We consider that inadequate service should be measured and reported, preferably at an individual customer level. Where data are not available at this level, distributors should report at the feeder or feeder-section level.

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33 SA Power Networks, *Draft Decision, Draft Distribution Reliability Measures Guidelines*, 11 August 2017, pp. 4–5.

34 Energex and Ergon Energy, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 7

35 CitiPower and Powercor, *Draft Distribution Reliability Measures Guidelines*, 11 August 2017, p. 3

36 CitiPower, Powercor and United Energy, *Email to the AER*, 21 November 2017: We [the distributors] estimate the cost of the proposed new reporting to be in the order of $20,000 for CitiPower, Powercor and United Energy. We would need to engage an IT developer to write and test new reports.

We will monitor performance under this definition to gauge the effectiveness of this approach and may refine this measurement method if necessary.

Consequently, we have amended the definition for inadequately served customers to read as follows:

> meaning a *customer* experiencing greater than 4 times the network average for unplanned SAIDI on a three-year rolling average basis compared with a network average customer.
>
> Note DNSPs must report to the AER annually:
>
> - the average unplanned SAIDI of the ***inadequately served customer***
> - the average unplanned SAIFI of the ***inadequately served customer***
> - the top five feeders with the most ***inadequately served customer***
> - the number of ***inadequately served customer*** of each of the above five feeders.

7 Matters specific to STPIS

7.1 Identifying an up-to-date VCR in the scheme

In our draft decision we proposed not to update the value of VCR originally included in the scheme. However, we will apply the latest available value for VCR to calculate the incentive rates for the STPIS on a reset by reset basis. We have adopted this approach because a further review of the VCR is currently on foot.

7.1.1 Submissions

We received a number of submissions on this matter:

- AusNet Services, CitiPower and Powercor and United Energy proposed that we should change the VCR value shown in the scheme as it is outdated.
- TasNetworks submitted that the VCR value stated in the STPIS should be removed.
- Ergon Energy and Energex both supported the use of an alternative nationally accepted VCR, such as that determined by AEMO, or one based on a new or more accurate calculation.

7.1.2 Our assessment

We have accepted and applied the VCR values published by AEMO in 2014 as a default arrangement for setting the STPIS incentive rates since 2014. Under the current scheme, distributors may however propose an alternative VCR value for AER consideration if they consider this to be preferable.

The AEMC has amended the rules to make the AER responsible for calculating VCRs in future.[37] We may include this revised, more accurate VCR in the scheme once it becomes available through further amendment to the STPIS.

In this instance, we do not consider it would be useful to revise the default VCR value for STPIS at this stage. However, we will apply a suitable VCR value in each reset as an interim measure.

7.1.3 Final decision

We do not propose to update the default VCR value for STPIS at this stage.

[37] AEMC, *Establishing values of customer reliability, Consultation Paper,* 10 May 2018.

7.2 Simplifying the complex formulas of the current scheme

The operation of the scheme could be simplified by implementing STPIS outcomes as a fixed dollar amount each year in accordance with actual performance; rather than as a percentage adjustment to the maximum allowable revenue (MAR).

7.2.1 Draft decision

Our draft decision considered a simplification to the STPIS calculation is desirable to address the following issues:

- The current scheme design adjusts the allowed revenue each year by the s-factor percentage. Hence, the MAR in the price control formula is not equal to that under the CPI-X model. The MAR of the following year must then be readjusted by applying the new s-factor after the removal of the s-factor of the previous regulatory year.
- The s-factor has a two-year time delay between the performance outcome and the adjustment of the MAR. Therefore, the s-factors of the last two years of a regulatory period are applied to the MAR of the first two years of the next period. Hence, there is a need to adjust for any step change in MAR between regulatory control periods—that is, 1 per cent of MAR in one period is not equal to the same percentage figures in the next period
- Under a percentage of MAR arrangement, a distributor may bank the s-factor results for more than a year if it expects to receive an increased revenue in future regulatory years due to a rising CPI or cost of debt.

7.2.2 Submissions

We received a variety of submissions:

- TasNetworks supported the simplification of the s-factor revenue adjustment.
- AusNet Services also supported the proposed changes and suggested further refinement to the s-factor formula.
- Ausgrid submitted that the s-factor formula should apply dollar adjustments to revenue caps, and as a percentage adjustment to price caps.
- SA Power Networks was concerned about the simplification of the s-factor calculation. It suggested that the calculation should reflect the time value of money because of the two-year lag between performance outcomes and the incentive payments to distributors.

7.2.3 Our assessment

The proposed changes were intended to simplify the formula and remove the need for an adjustment between regulatory control periods. However, we agree that the rewards/penalties under STPIS should recognise the time value of money.

We agree that the s-factor expression should work with the control mechanism. This requires a dollar value adjustment for a revenue cap. We have therefore adjusted the s-factor calculation, to reflect the time value of the incentive payments, as detailed in Appendix D.

We also consider that our proposed use of a dollar-value calculation will work under both price cap and revenue cap price control frameworks.

We intend to include the s-factor outcomes as a part of the I-term of the price control formula. This component of the price control formula is an adjustment of a distributor's allowable revenue in dollar terms, irrespective of whether it is under a price cap or revenue cap price control framework.

7.2.4 Final decision

We will proceed with a simplification of the s-factor calculation. However, we will adjust the formula to account for the CPI change between the year of the actual performance outcome and the year in which the financial outcome is implemented.

7.3 Adjusting the targets where the reward or penalty exceed the revenue cap under STPIS

When a distributor's actual performance is much better or worse than the performance targets, this may lead to a financial reward or penalty under the STPIS exceeding the revenue at risk under the scheme. In such a case, the distributor's actual performance in a particular period must be adjusted for the purpose of setting the performance targets for the subsequent period.

This is to ensure that the distributor's performance targets in the future reflect the financial reward/penalty that they have received. In particular, a distributor should not be allocated with an easy target because of historical poor performance. This is particularly so when customers have not received the appropriate compensation for poor performance.

While the current STPIS specifies that an adjustment must be made, the scheme currently does not set out how this is to be done.[38]

[38] Clause 3.2.1(a)(1B) of STPIS.

We consider that there needs to be a clear method to make the adjustment which reflects the customers' VCR values. In the issues paper, we proposed a method to adjust the targets.

7.3.1 Draft decision

Our draft decision proposed to make adjustments to the performance targets for SAIDI and SAIFI to make them consistent with the cap on revenue at risk under STPIS. To avoid complexity, we did not propose to adjust the MAIFI or telephone answering targets.

7.3.2 Submissions

We received a number of submissions from distributors on this matter:

- Essential Energy supported the adjustments to targets where rewards/penalties exceed the cap under STPIS.
- SA Power Networks, Ergon Energy and Energex agreed that the performance in a year where the STPIS cap is exceeded should be adjusted. However, they were concerned about our proposed method. They proposed that we adopt the methods proposed by them in the last distribution determination, which had been accepted by the AER.

7.3.3 Our assessment

We agree that a number of methods can be used to adjust the performance targets under STPIS. The purpose of the adjustments is to ensure neither customers nor the distributors will receive a financial windfall when the revenue at risk cap is breached.

We do not think that the standard 5 per cent revenue at risk cap will often be breached. If it is, we would expect that the STPIS results would quickly return to the normal level without the need for further adjustment to the targets.

The STPIS that is applied to the South Australia and Queensland distributors does not include the MAIFI component. Hence, the previously accepted approaches are not readily transferrable to the Victorian application, which contains the MAIFI component.

We have revised the methodology to clarify the treatment of the telephone answering component and to remove uncertainties in implementing the adjustments.

7.3.4 Final decision

Our final decision is to adjust the target where the rewards or penalty exceed the revenue cap under STPIS in accordance with Appendix E of this final decision.

7.4 Transitional arrangement to implement the new STPIS

In its submission, Evoenergy suggested that we should be flexible in implementing the revised STPIS, given that the current ACT/NSW revenue determination is in progress.

To implement the revised STPIS, we need historical performance data under the new measurement method. If a distributor is unable to back-cast its historical performance data, it would not be possible to implement the revised version of the STPIS in full—specifically the new 3-minute threshold to define momentary interruption.

Therefore, we intend to be flexible in implementing the revised scheme. If the back-cast historical data are not available at the next distribution determination, we will retain the historical definitions for SAIDI, SAIFI and MAIFI based on the previous 1-minute threshold for defining a momentary interruption. However, the changes to the 40% SAIFI / 60% SAIDI incentive weighting ratio and other simplifications to the scheme will be implemented in full.

7.5 Further future development of STPIS

In the draft decision we noted that industry developments, including increasing photovoltaic installations, battery storage and increased use of distributed energy resources, pose challenges for STPIS. While it is not possible to address all such issues in the current timeframe for this review, we will consider these issues further when these trends and developments are clearer.

7.5.1 Submissions

Ausgrid argued that the existing customer service component is limited to telephone answering by call centres and is not a meaningful indicator. Ausgrid suggested a complaint based metric should also be considered in the STPIS.

IPART also suggested that we consider quality of supply as a part of STPIS measures in future.

S&C Electric commented on the effect of momentary interruptions (MAIFI) on distributed generators. It should be noted that, due to the limitation of adequate recording devices, the momentary interruptions component of the STPIS is only implemented in Victoria.

7.5.2 Our assessment and conclusion

We will consider these issues as part of our next review of STPIS.

A Summary of submissions on our proposed 40:60 SAIFI:SAIDI incentive rate ratio

The table below summarises the submissions received.

Table A1: Summary of submissions on SAIDI/SAIFI incentive ratio

Issues	Submissions	Our response
1. Reduce the weighting ratio on SAIFI incentive from 50% to 40%	Jemena supported the change (no reasons stated). PIAC supported the change to 40% SAIFI / 60% SAIDI as a means of removing the bias towards SAIFI-related network augmentation over SAIDI-improving opex. S&C Electric commented that: • By revising the ratio of SAIDI to SAIFI and giving a higher weighting to SAIDI, the duration of outages may be addressed, most likely through capex approaches. • In OFGEM's RIIO-ED1 Scheme, the ratio is 27 % on SAIFI and 73% on SAIDI. . And, this has seen improvements in both SAIDI and SAIFI. Ergon and Energex acknowledged that a capex investment does not deliver similar proportional improvements between SAIDI and SAIFI. Evoenergy submitted that the scope for significant improvement for the ACT network is small due to limited emergency response work crews. As a result achieving further significant improvements in SAIDI would face diminishing returns to expenditure even under the current 50:50 ratio.	We will move to a 40% SAIFI / 60% SAIDI incentive structure because: • This would reduce the driver for focusing on a capex approach to reduce SAIFI and to use more innovative capex to address both SAIFI and better fault response (see S&C comments, and CitiPower/Powercor/UE comments below). • We have enough information to make this change. Further changes may be considered once our works on reviewing the VCR is completed. • A similar ratio in the UK has led to more balanced outcomes.

<table>
<tr><th>Issues</th><th>Submissions</th><th>Our response</th></tr>
<tr><td>2. Whether the current scheme would lead to a greater focus on capex options to improve reliability</td><td>CitiPower/Powercor/United Energy submitted that:
Capital solutions are often the most effective means to reduce SAIDI and SAIFI.
Importantly, capital solutions can specifically target the time to restore supply (SAIDI). For example they have recently undertaken a number of capital programs to reduce SAIDI.[39]
Seeking to promote opex solution is inefficient and ineffective.
Ergon and Energex submitted that there is no 1:1 relationship between capex and SAIFI, and opex and SAIDI. Therefore, there is no corresponding bias towards a capex option to improve supply reliability. However, capex delivers better value for money than opex.

TasNetworks submitted that current incentive rates do not bias towards capex; changing incentive rates may have negative consumer impact, as a result of inconsistency between the increased network costs for reliability improvements and customer perception of value—especially in jurisdictions where the marginal cost for SAIDI improvement is high.</td><td>Five distributors confirmed that capex solutions are often the most effective options.

We are concerned that the current incentive structure results in outcomes at the nearby end of the feeder receive the benefit while those at the end of the feeder receive fewer benefits of network expenditure. This is true regardless of whether the expenditure is capex or opex.

The proposed 40% SAIFI / 60% SAIDI rates should provide a more balanced incentive to address both SAIFI and SAIDI.

Further, as explained in the example at the end of this paper, the proposed 60:40 ratio should provide a more symmetrical incentive than the current 50:50 ratio.</td></tr>
</table>

[39] For example:

- New technology which enables quicker resolution of faults in 2017. The technology automates switching processes currently conducted manually in the control room. The technology will reduce fault duration through faster switching but will not reduce fault incidence. This is an example where a capital solution is deployed to improve outage duration. The benefits will be realised gradually as the technology is rolled out across the network.
- An IT tool is deployed in 2016 to improve scheduling and dispatch of field crew. As this tool is rolled out, field crew will be deployed more efficiently, reducing travel times and enabling faster outage response.
- Installation of auto-reclosers, switches and monitoring devices to narrow the fault area. Field crew are then deployed to a more targeted location enabling quicker identification of the fault cause and faster restoration. This is an example where capital solutions are more efficient than operating solutions

Issues	Submissions	Our response
3. AER's analysis to show the average supply restoration time (CAIDI) is increasing based on the formula that CAIDI=SAIDI/SAIFI is not accurate, because we did not consider the effect of replacement of manually operated switches by auto-reclosers	AusNet submitted that increase in CAIDI is "an outcome of the STPIS scheme working, rather than a reflection of deteriorating customer reliability outcomes". It used a worked example to show that replacing existing manual-operated switches with auto-reclosers will result in a 7.1% increase in CAIDI. SA Power Networks also used an example to show that replacement of a manual switch with ACR will result in increase in CAIDI. For the example provided, the increase is 12.6%.	CAIDI for the Victorian distributors has increased by 30% on average over a ten year period. The replacement of manual switches by auto-reclosers only account for less than half of this increase. Hence, we believe that there has been a real increase of the average supply restoration time.
4. The current scheme has a feedback effect because the SAIFI incentive rate is tied to the CAIDI figures of the previous period	AusNet and SAPN showed that replacing existing manually operated switches with auto-reclosers would result in an up to 12.6 per cent apparent increase in CAIDI based on the equation CAIDI=SAIDI/SAIFI. This is less than half the increase actually experienced.	The distributors confirm the existence of the feedback loop, even if the actual fault repair time does not change. After allowing for the effect of installing auto-reclosers, there has been an increase in CAIDI.

<table>
<tr><th colspan="3">Other objections raised</th></tr>
<tr>
<td>5. Claim that customers prefer to replace SAIDI than SAIFI</td>
<td>Ausgrid considers customers would prefer a reduction in the frequency of outages (SAIFI) compared to their duration (SAIDI).</td>
<td>While customers would prefer fewer interruptions, this does not mean that they are happy with long outages and outage time getting longer.

Based on AEMO's 2014 VCR study, 87 per cent of the distributors' customers—residential customers—prefer short outages to long outages. However, business customers (representing 13 per cent of the customer base) prefer less number of shorter outages over single long outages.

We used the example of rural customers on feeders with 3 outages of 80 minutes to further demonstrate the issues with the current STPIS incentive rates
The SAIFI target is 3 and the SAIDI target is 3x80=240 minutes. The SAIFI incentive rate is about the equivalent of 80 minutes in SAIDI reduction.
The following outcomes will receive equal treatment from STPIS under the current scheme:
6 outages of 3 minutes duration
1 outage of 400 minutes (6 hours 40 minutes) duration.
We think most customers would prefer the second scenario over the first scenario. The impact on a customer's daily life is much greater for a long outage than for the combined effect of a few short outages.</td>
</tr>
</table>

6. The proposed 60/40 ratio was not based on adequate modelling/analysis	Evoenergy argues that there is lack of objective evidence or methodology to justify the change to the SAIDI/SAIFI ratio. AusNet Services argued that it has not been established that the change is an efficient outcome and is consistent with consumers' preference. IPART suggested a cost benefit analysis should be undertaken to identify the suitable solution.	The current 50:50 ratio and the incentive rate calculation formula were initially based on the SECV's earlier scheme, rather than through detailed modelling. We now understand that this ratio appears to be putting too much weight on SAIFI as well as creating a feedback loop on the SAIFI incentive. The proposed 40/60 ratio should have a more symmetrical incentive to address both frequency and duration of outages than the current 50/50 ratio. This would reduce the driver for focusing on a capex approach to reliability improvement and provide more incentives to at least slow down the deterioration in supply restoration time, i.e. limiting the extent of this problem rather than removing it. We consider we have enough information to make this significant but not large change to the incentive weights. Similar arrangement of a ratio that favours SAIFI less than SAIDI is already in operation in the UK and has had a desired effect in encouraging more balanced outcomes.
7. The AER's observation as presented in the draft decision on STPIS was based on one regulatory period of the schemes operation	Ergon and Energex acknowledged that the improvement from a capex investment does not deliver proportional outcomes. However, the data and outcomes reflective of one regulatory control period (as presented in the Explanatory Statement) are insufficient to suggest a conclusion there is an overall disproportional worsening of customer average interruption duration index (CAIDI). A longer time series would be required to support this conclusion (if at all).	AER's STPIS has been in operation for one and half regulatory periods for Victoria, Queensland and South Australia. Further, a similar scheme was implemented in Victoria in 2005. The CAIDI increasing trend was observed in Victoria over a 10-year period. Details about the Victorian experience are provided in Appendix B.
8. There should be a flexible approach to the incentive rates	Ausgrid suggested a flexible approach to the incentive rates depending on each distributor's situation.	While we accept the logic of such approach, in order to implement this approach, we need to establish a framework to identify a suitable method, which is not covered by the scope of this review. That said, the difference in VCR values across jurisdictions does provide for some level of targeted response or flexibility in the existing scheme. The AER intends to do further work on VCR.

9. The need to clarify the relationship between capex and opex	Essential Energy argued that the AER should clarify how it will translate SAIDI related on-going operating expenditure under the scheme into its benchmarking of operating expenditure.	The objective of STPIS is to discourage distributors from reducing cost at the expense of declining supply reliability and customer services; and only to improve supply reliability where customers are willing to pay for it. It is up to the individual distributor to find its own balance regarding the capex/opex trade off when planning future reliability improvement works, taking into consideration the EBSS and CESS.

Submission list

- Ausgrid - 8 February 2018
- AusNet Services - 9 February 2018
- CitiPower, Powercor Australia, United Energy Distribution - 9 February 2018
- CitiPower, Powercor Australia, United Energy Distribution - 22 February 2018
- Energex and Ergon Energy - 9 February 2018
- Essential Energy - 8 February 2018
- Evoenergy - 8 February 2018
- Independent Pricing and Regulatory Tribunal (IPART) - 9 February 2018
- Jemena Electricity Network (JEN) - 9 February 2018
- SA Power Networks - 9 February 2018
- S&C Electric - 9 February 2018
- Southern Sydney Regional Organisation of Councils (SSROC) - 9 February 2018
- TasNetworks - 8 February 2018
- Public Interest Advocacy Centre (PIAC) - 15 March 2018

The proposed 40% SAIFI / 60% SAIDI ratio should provide a more symmetrical incentive to address both frequency and duration of outages than the current 50% SAIFI / 50% SAIDI ratio.

Consider the following example: A feeder has a historical average of 3 outage events of 80 minutes duration each. The distributor has the following options for reducing or increasing number of outages events under the 50/50 ratio:

- If the number of outages reduces to 2 events, the distributor would receive a reward under STPIS if the average restoration time is less than 160 minutes (much higher than the previous 80 minutes restoration time).
- If the number of outages increases to 4 events, the distributor must reduce the average restoration time to less than 40 minutes in order to receive a reward under STPIS.

Conversely, under the proposed 40% SAIFI / 60% SAIDI:

- If the number of outages reduces to 2 events, the distributor will receive a reward under STPIS if the average restoration time is less than 146.7 minutes (lower than the 160 minutes under 50/50 ratio).
- If the number of outages increases to 4 events, the distributor must reduce the average restoration time to less than 46.7 minutes in order to receive a reward under STPIS (higher than the 40 minutes under 50/50 ratio).

Conclusion

The 40% SAIFI / 60% SAIDI ratio will result in a narrower band in terms of the CAIDI outcome (between 46.7 and 146.7) compared with that for a 50/50 ratio (between 40 and 160). This provides a better balanced incentive.

B Appendix B: STPIS operations history in Victoria

In the draft decision and our earlier issues paper on this matter, we only presented the current STPIS results. The AER's STPIS has been in operation for one and half regulatory periods for Victoria, Queensland and South Australia. Further, a similar scheme was implemented in Victoria in 2005. The CAIDI increasing trend has been observed from this period to the present time (10 years).

Table B1 presents the historical trend. Except for the CAIDI outcomes of Jemena's urban feeders, all Victorian distributors' CAIDI increased, some significantly by up to 57 per cent. The average increase is 30 per cent over a 10 year period.

Figure B1 presents the trends of increasing CAIDI for all feeder types over this period.

Figure B1: Victorian distributors—trend of CAIDI movement 2006-2015

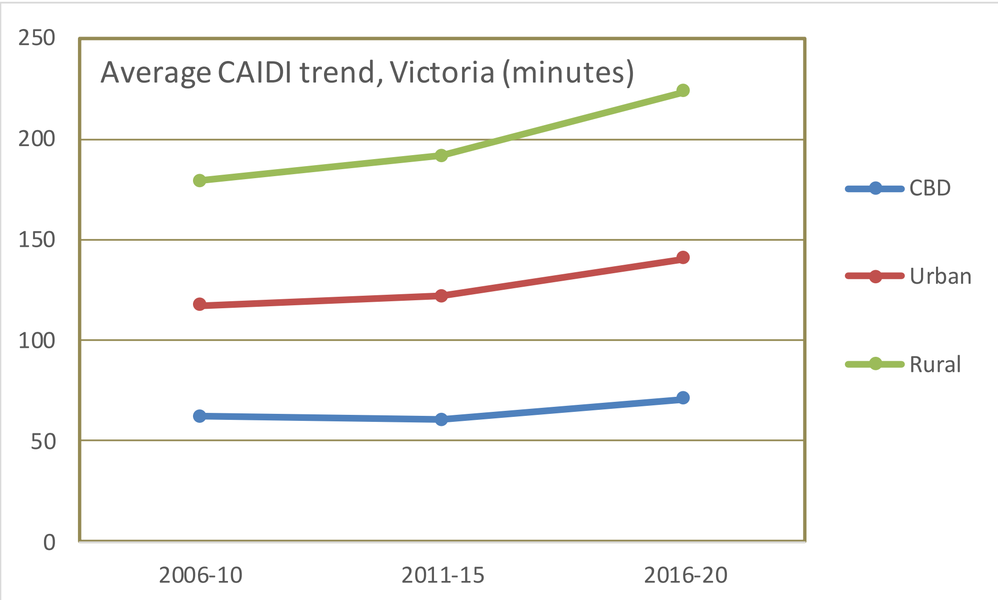

Table B1: Victorian distributors—Historical trend of CAIDI movement 2006-2015

Feeder type	Distributor	CAIDI performance target implied in distribution determinations (based on the ratio of SAIDI/SAIFI targets)			Percentage increase from 2004 to 2014	Trend
		2006-10 (under ESCV's similar scheme) [abc]	2011-15 [d]	2016-20 [e]		
CBD	CitiPower	62	61	71	↑ 14%	increasing
Urban	CitiPower	44	50	68	↑ 55%	significant increase
	Jemena	57	61	58	↑ 1%	stable
	United Energy	56	61	68	↑ 23%	increasing
	Powercor	60	65	79	↑ 32%	significant increase
	AusNet	60	70	74	↑ 24%	increasing
Rural feeders (combining both short and long rural feeders) [f]	Jemena	50	59	75	↑ 49%	significant increase
	United Energy	47	57	74	↑ 57%	significant increase
	Powercor	81	84	101	↑ 25%	increasing
	AusNet	69	79	82	↑ 19%	increasing
Average increase across all distributors and feeder types					↑ 30%	

a: Essential Services Commission of Victoria (ESCV), Electricity Distribution Price Review 2006–10, Final Decision Vol. 2, October 2005

b: While the ESCV had a similar scheme in 2001-5 period. However, the scheme allocated some of the incentives to planned outages. We cannot compare this earlier scheme with the current scheme, which excludes planned outages.

c : The performance targets for the 2006-10 period were based on the historical averages of 2000-04

d: The performance targets for the 2011-15 period were based on the historical averages of 2005-09

e: The performance targets for the 2016-20 period were based on the historical averages of 2010-14

f: The previous ESCV 2006-10 scheme did not distinguish short and long rural feeders, for effective comparison purpose, we converted all rural feeders into a single category.

C Summary of submissions and our response on other issues

C.1 Changing the threshold definition of momentary interruptions

Issues	Submissions	Our response
Changing the threshold from 1 minute to 3 minutes	ENA and distributors supported the change to momentary interruptions but had a concern that some distributors may not be able to back cast the data. S&C Electric did not support the change as it would affect large customers and solar photovoltaic systems.	This change provides additional incentives to restore supply quickly, where the benefit outweighs the cost. Distributors will be better able to implement network automation that can convert some of the longer sustained unplanned outages into short-term momentary outages. This approach should benefit all customers, including industrial and commercial customers. It does not mean that distributors will delay restoring power where they can currently do so within one minute. As identified by AEMC, it is not economically feasible or even possible to eliminate all sustained interruptions. All network users need to take their own necessary precautions against unplanned supply interruptions.[40]

C.2 Different types of momentary interruption measurement method (MAIFI and MAIFIe)

Issues	Submissions	Our response
Use MAIFI or MAIFIe for reporting purposes	Essential Energy, Energex and Ergon Energy supported using MAIFIe to measure momentary interruptions but noted that they did not have the capacity to report this measure.	We agree with the AEMC that MAIFIe is the preferred measure to measure momentary interruption. MAIFI will be applied where distributors are unable to report MAIFIe data due to measurement restrictions.

[40] AEMC, *Review of Distribution Reliability Measures, Final Report*, 5 September 2014, p.14.

C.3 Additional exclusions for performance measures

Issues	Submissions	Our response
Proposed new exclusions regarding outages under the direction of state or federal emergency services authorities, and modification to the current exclusion criterion regarding outage due to failure of transmission connection assets	PIAC supports the exclusions because they are outside distributors' control. Essential Energy supports the exclusions. Ergon and Energex seek clarity as to whether momentary interruptions for the past 5 years should be recalculated to account for all interruptions of up to 3 minutes duration. ENA suggested that additional guidance on what constitutes adequate planning or good industry practice should be provided. Ergon and Energex suggest a further exclusion for customer installation faults.	If a distributor is unable to back cast its historical performance data, it would not be possible to implement the revised version of the STPIS. We propose a flexible approach to the implementation of the revised scheme subject to availability of back cast data. If the back cast historical data are not available at the next distribution determination, we will apply the current scheme. There are two scenarios associated with a customer's electrical installation failures: -The distributor's network is still intact despite the failure of the customer's equipment. Hence, only the specific customer's electricity supply is not available due to automatic protection equipment or as the result of a malfunction of the customer's installation. -The distributor's network is affected by the customer's equipment failure, resulting in other customers also being without supply. Under the first scenario, there is no loss of supply to other customers. There is no need to exclude the event when calculating reliability measures. Under the second scenario, there is a loss of supply to other customers. The distribution network can install appropriate protection equipment to safeguard its own network and protect other network users. Hence, exclusion under this scenario is not appropriate.

C.4 Additional exclusion of catastrophic events in addition to the current major event days exclusions

Issues	Submissions	Our response
No exclusion of catastrophic event days, before the standard 2.5 beta method is applied to the threshold to identify major event days	IPART supported our recommendation and agreed with our concerns on this matter. It further commented that (1) removal of catastrophic events before applying the IEEE 2.5 beta method would only increase the number of excluded days in a way not intended by the IEEE standard, and (2) such an approach is not fair to the customers in cost/benefit terms. PIAC submitted that while there is no consistent method to identify catastrophic days, the AER should exclude such events because they are outside of the control of a distributor, infrequent and, over the long term, unpredictable in terms of the location and nature of impact. Essential Energy argued that the AEMC's recommendation should not be ignored just because a clear identification method is absent. It submitted that the AER should adopt a 4.15 beta method or a graphical area based method in the interim. SA Power Networks argued that we were inconsistent in arguing that there should be an objective method to identify major event days because we have previously allowed a variety of different methods to identify major event days.	There are two applications of the treatment of catastrophic events: • for consistent measurement of supply reliability across all jurisdictions • for defining the coverage areas of STPIS of each distributor. SA Power Networks' contention somehow conflated the two applications. It correctly pointed out that the current STPIS does have flexibility for distributors to have a higher threshold of the major event day (MED) boundary. This would reduce the number of exclusion days in a year or increase the level of accountability of the distributor who opts for a higher MED boundary. Whereas, the purpose of the DRMG is to establish a consistent measurement method for supply reliability.

C.5 Flexible approach to the definition of urban feeders

Issues	Submissions	Our response
Definition of Urban feeders	CitiPower and Powercor proposed further refinement to the definition. This is to take into account where there are significant changes in feeder length, for example as a result of network reconfiguration such as the establishment of a new zone substation. Endeavour Energy sought flexibility to enable feeders to be classified to a more intuitive classification. For example, new feeders may only be lightly loaded during the initial stage of development.	Feeder lengths may change significantly because of network reconfiguration. Hence, the average feeder length over a three year period would be a better measurement base. We consider that feeders should be classified based on the actual load density rather than based on the forecast future load density, which may or may not eventuate. The purpose of having common definitions is to provide consistency for reporting purposes and to limit gaming. We consider that distributors should not be able to reallocate feeders to classifications. That said, distributors may reclassify feeders during the revenue determination process.

C.6 Supply outages due to malfunction of energy meter

Issues	Submissions	Our response
Whether outages due to the malfunction of energy meters should be included in the performance measures for supply reliability	Energex and Ergon Energy argued that outages cause by the malfunction of meters should be excluded from supply reliability measurements	Since December 2017, the responsibility for metering installation has resided with energy retailers. We therefore consider that supply outages due to meter malfunctions should be excluded from the definition of "outage" in the guideline. Hence, the definition of supply interruption should be measured at the point of supply.

C.7 Improving consistency of measurement methods

Issues	Submissions	Our response
Reporting approach	Energex and Ergon Energy supported a consistent approach to performance reporting.	A consistent approach to report information is essential to accurate performance monitoring.

C.8 Capping guaranteed service level (GSL) payments

Issues	Submissions	Our response
Introduce a cap for the total GSL payments for individual customers, similar to the current $454 per annum cap of Queensland.	Ergon Energy and Energex argued that the STPIS scheme GSL payments go beyond existing jurisdictional GSL arrangements (in Queensland). They recommended a cap for the total GSL payments should be introduced for individual customers, similar to the current $454 per annum cap of Queensland.	The current AER GSL scheme already has a cap on the maximum amount that can be paid for all interruptions to supply. The total GSL payments incurred by distributors do not represent a significant proportion of their revenues each year. Further, there are no limits under the s-factor calculation on the total frequency and duration of supply interruptions.

C.9 Treatment of unmetered supply

Issues	Submissions	Our response
Treatment of unmetered supply	Jemena supports our draft decision. Central NSW Councils, SSROC, Western Sydney Regional Organisation of Councils and Local Government NSW argued that unmetered supplies, street lighting and public lighting, should be included in performance measures. They also outlined that street lighting outages can last for long periods of time and street lighting is held to a substantially lower reliability standard than for all other classes of customers.	It is important to maintain high reliability standards for street lighting. However, we consider that including unmetered connections within supply reliability measures would not address the issues raised by the councils and would be unlikely to have a material impact on public lighting service standards. It is unlikely that long street light outages are purely due to electricity supply issues. Unless the lighting is supplied by part of the network without any other metered customers, any long outage will be identified, captured in performance reliability measures and addressed by the relevant distributor. Very long street light outages appear more likely to be the result of maintenance issues than are due to power supply outages. This issue of proper maintenance of public lighting is out of scope for the development of the DRMG. The service standard for public lighting is likely to be resolved by changes to the NSW Public Lightning Code. We understand that the NSW government is currently reviewing its public lighting code to address the councils' concerns. There are not many unmetered connections other than street lights. Including such loads in performance reporting is unlikely to provide useful information on the level of service provided to these connections.

C.10 Reporting of customers receiving inadequate level of service reliability

Issues	Submissions	Our response
Definition of inadequate level of service reliability for customers	Essential Energy indicated that it applies SAIFI thresholds at the feeder segment level to capture customers who experience the worst 1 per cent of network reliability. A number of distributors and the ENA suggested that the definition of worst served customers should have regard to the current minimum service standards prescribed in the relevant jurisdiction. SA Power Networks argued that using the network average for unplanned SAIDI on a three-year rolling average basis may inadvertently capture customers who should not be classified as inadequately served. This is because one very bad SAIDI year may result in a feeder being classified as having an inadequate level of reliability despite the other two years not having poor performance.	Jurisdictional minimum service level standards are typically the minimum average standard that distributors are required to provide. Such levels would not normally represent the threshold to define customers receiving inadequate supply reliability. Where a distributor does not meet such minimum level, it does not necessarily follow that the service level is inadequate by comparison with other similar customers. Network characteristics in Australia vary greatly. Hence, there cannot be a single threshold SAIDI and SAIFI criterion that can identify who is “worst served”. Further, reliability outcomes may vary from year to year. We need to start monitoring the level of service to these customers so that suitable incentives or compensation framework can be developed in future. We maintain our proposal to set the threshold level to cover the bottom 10 per cent of customers by service reliability. We propose to modify the reporting requirements. Where detailed data based on individual customer’s experience are not available, distributors may report at feeder or feeder section level.

C.11 Identifying an up-to-date VCR in the scheme

Issues	Submissions	Our response
Remove the VCR shown in the scheme because it is outdated.	AusNet Services, CitiPower and Powercor and United Energy proposed that we should change the VCR shown in the scheme because it is outdated. TasNetworks submitted that the VCR stated in the STPIS should be removed. Ergon Energy and Energex supported the use of an alternative nationally accepted VCR, such as that determined by AEMO, or one based on new or more accurate research on VCR.	The AEMC amended the rules to make the AER responsible for establishing VCRs in future. We will include this new, more accurate VCR in the STPIS once it is available. We do not consider that it would be worthwhile to review the default values included in the STPIS at this stage. We will however apply a suitable VCR value in each reset as an interim measure.

C.12 Simplifying the complex formulas of the current STPIS scheme

Issues	Submissions	Our response
Further refinement to the s-factor formula.	TasNetworks supported the simplification of s-factor revenue adjustment. AusNet Services also supported the proposed changes and suggested further refinement to the s-factor formula. SA Power Networks was concerned about the simplification of the s-factor calculation. It suggested that the calculation should reflect the time value of money.	The proposed changes are intended to simplify the formula and remove the need for adjustments between regulatory control periods. However, we agree with the distributors' concerns that the rewards/penalties should be recognise the time value of money.
The s-factor expression should be aligned with control mechanism - that is dollar adjustment for revenue cap, and percentage adjustment for price cap.	Ausgrid submitted that the s-factor expression should apply dollar adjustment for revenue caps, and percentage adjustment for price caps.	Our proposed use of dollar values will work under both price cap and revenue cap price control frameworks. We intend to include the s-factor outcomes as a part of the I-term of the price control formula. This component of the price control formula is an adjustment of a distributor's allowable revenue in dollar terms, irrespective of whether it is under a price cap or revenue cap price control frameworks.
Further refinement is required to the s-factor formula	AusNet Services suggested further refinement to the s-factor formula.	We have made further refinement to the s-factor calculation, to reflect the time value of the incentive payments relating to the two year time delay between the performance incentive and the incentive payments.

C.13 Adjusting the targets where the reward or penalty exceed the revenue cap under STPIS

Issues	Submissions	Our response
Proposed adjustment to revenues where rewards/penalty exceeds the cap under STPIS	Essential Energy supported adjustments to the targets where rewards/penalty exceeds the STPIS cap. SA Power Networks, Ergon Energy and Energex agreed that the performance in a year where the STPIS cap is exceeded should be adjusted. But they were concerned about our proposed method. They proposed that we adopt the methods proposed by them in the last distribution determination, which had been accepted by the AER.	We will clarify the treatment of telephone answering component to remove uncertainties in implementing the adjustments. We do not think that the standard 5% revenue at risk cap will often be breached. If it does, we expect that the STPIS results would quickly return to normal level without the need for further adjustment to the target. The STPIS that is applied to South Australia and Queensland distributors does include the MAIFI component. Hence, the previously accepted approaches are not readily transferrable to the Victorian application, which contains the MAIFI component.

C.14 Transitional arrangement to implement the new STPIS

Issues	Submissions	Our response
Application of the new STPIS	Evoenergy suggested that we should be flexible in implementing the revised STPIS, given that the current ACT/NSW revenue determination is now in progress.	We intend to be flexible in implementing the revised scheme. If the back cast historical data are not available at the next distribution determination, we will be applying the current scheme. However, the 40% SAIFI / 60% SAIDI incentive weighting ratio and other simplifications to the scheme will be implemented in full.

C.15 Further development of STPIS

Issues	Submissions	Our response
Further development of STPIS	Ausgrid submitted that the existing customer service component is limited to fault call centre telephone answering and is not a meaningful indicator. Ausgrid suggested a complaint based metric should also be considered in the STPIS. IPART also suggested that we consider quality of supply as a part of the STPIS measures in future. S&C Electric commented on the effect of momentary interruptions (MAIFI) on distributed generators. Due to limitation of adequate recording devices, the MAIFI component is only implemented in Victoria.	We consider these suggestions a matter for our future review because they require extensive consultation or are out of scope under the current review.

D Simplifying the calculation of the s-factor

Below is proposed formula to apply to standard control services revenues. We consider that the formula gives effect to the revenue cap.

We also added annotations of "$" and "%" signs to further clarify which terms are in dollar values and which ones are in percentage terms.

Figure D.1 Proposed revenue cap to apply to distributors' standard control services

1. $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ $\qquad i = 1, \ldots, n \text{ and } j = 1, \ldots, m \text{ and } t = 1, 2 \ldots, 5$
2. $TAR_t = AAR_t + I_t + B_t + C_t$ $\qquad \mathrm{t} = 1, 2 \ldots, 5$
3. $AAR_t = AR_t$ $\qquad \mathrm{t} = 1$
4. $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$ $\qquad \mathrm{t} = 2, \ldots, 5$

where:

TAR_t is the total allowable revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

t is the regulatory year.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the sum of incentive scheme adjustments in year t. Likely to incorporate but not limited to revenue adjustments for f-factor, Demand management innovation allowance (DMIA), Demand management innovation allowance mechanism (DMIAM), Demand management incentive scheme (DMIS) and s-factor $S_t^{\$}$ as applicable. To be decided in the distribution determination.

$S_t^{\$}$ is the s-factor for regulatory year t, expressed as real dollars amounts.[41] As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.

[41] The meaning for year "t" under the price control formula is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the unders and overs account. To be decided in the distribution determination.

C_t is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER. It will also include any end-of-period adjustments in year t. To be decided in the distribution determination.

ΔCPI_t is the CPI for year t, as determined in the relevant distribution determination.

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

Figure D.2 Proposed S-factor formula

5. $S_t^{\$} = AR_{t-2} S_{t-2}^{\%} \times \frac{CPI_{t-1}}{CPI_{t-3}} - Sb_t^{\$} + Sb_{t-1}^{\$} \times \frac{CPI_{t-1}}{CPI_{t-2}} \qquad t = 1, \ldots, 5$

$S_t^{\$}$ is the s-factor amount for regulatory year t.[42] As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.[43]

AR_{t-2} For t=1 and 2, AR_{t-2} represents the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year 4 and 5 of the previous regulatory control period, respectively.

CPI_t is the CPI index for year t, as determined in the relevant distribution determination.

$S_{t-2}^{\%}$ is the sum of the raw s-factors for all parameters for regulatory year t -2, before banking, expressed as a percentage of revenue (or prices) calculated annually through the compliance assessment. For t =1 and 2, $S_{t-2}^{\%}$ represents the sum of the raw s-factors for year 4 and 5 of the previous regulatory control period, respectively.

$Sb_t^{\$}$ is the s-bank for the current regulatory year t, expressed as real dollars amounts.

$Sb_{t-1}^{\$}$ is the s-bank for the previous regulatory year t–1, expressed as real dollar amounts. For t =1, it represents the s-bank for year 5 of the previous regulatory control period.

42 The meaning for year “t” under the price control formula is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this decision.

43 AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

E Adjusting the targets where the reward or penalty exceed the revenue cap under the STPIS

We propose the following steps to make adjustments to the performance targets:

Assuming the calculated total raw s-factor for the regulatory year t is $(P + P_0)\%$, with $P\ \%$ being residue above or below the revenue at risk, typically $\pm 4.5\%$ exclusive of telephone response parameter of $\pm 0.5\%$, as set during the revenue determination. We also assume the distributor only has CBD and urban networks. We need to make the adjustment according to the SAIDI and SAIFI targets for the forthcoming regulatory period, between CBD and urban networks, based on the incentive rates respectively. The VCR of previous regulatory control period will be adopted for the calculation of SAIFI and SAIDI incentive rates.

First, consistent with our proposed new ratio between SAIDI and SAIFI incentive rates, we allocate 0.6P to SAIDI minutes and 0.4P to SAIFI.

1. $P = P_{SAIDI} + P_{SAIFI}$
2. $P_{SAIDI} = 0.6P$
3. $P_{SAIDI} = P_{\mathrm{SAIDI,CBD}} + P_{\mathrm{SAIDI,urban}}$
4. $P_{SAIDI,CBD} = P_{SAIDI} \times \frac{ir_{\mathrm{SAIDI,CBD}}}{ir_{\mathrm{SAIDI,CBD}} + ir_{\mathrm{SAIDI,urban}}}$
5. $P_{\mathrm{SAIDI,urban}} = P_{SAIDI} \times \frac{\mathrm{ir}}{ir_{SAIDI,CBD} + ir_{\mathrm{SAIDI,urban}}}$
6. $SAIDI_{CBD} = \frac{P_{\mathrm{SAIDI,CBD}}}{ir_{\mathrm{SAIDI,CBD}}} = \frac{P_{SAIDI}}{ir_{\mathrm{SAIDI,CBD}} + ir_{\mathrm{SAIDI,urban}}}$
7. $SAIDI_{Urban} = \frac{P_{Urban}}{ir_{\mathrm{SAIDI,urban}}} = \frac{P_{SAIDI}}{ir_{\mathrm{SAIDI,CBD}} + ir_{\mathrm{SAIDI,urban}}}$
8. $SAIDI_{CBD} = SAIDI_{Urban}$

Note: $SAIDI_{CBD}$ and $SAIDI_{Urban}$ refer to the adjustment amount of the SAIDI targets where the reward or penalty exceeds the revenue cap. Y_n refers to the number of years covered by the regulatory control period where such adjustments are necessary. Typically this value is 5.

Therefore, SAIDI performance targets for CBD and urban networks require the same adjustment. Dividing this adjustment by the number of years covered by the relevant regulatory control period"Y_n" , the corresponding adjustment to the annual performance target is derived:

9. $\frac{1}{Y_n} SAIDI_{CBD} = \frac{1}{Y_n} \frac{P_{SAIDI}}{ir_{\mathrm{SAIDI,CBD}} + ir_{\mathrm{SAIDI,urban}}} = \frac{1}{Y_n} \frac{0.6P}{ir_{\mathrm{SAIDI,CBD}} + ir_{\mathrm{SAIDI,urban}}}$

Secondly, we allocate the rest of P to SAIFI

10. $P_{SAIFI} = 0.4P$

11. $P_{SAIFI} = P_{\text{SAIFI,CBD}} + P_{\text{SAIFI,urban}}$

12. $P_{SAIFI,CBD} = P_{SAIFI} \times \frac{ir_{\text{SAIFI,CBD}}}{ir_{\text{SAIFI,CBD}}+ir_{\text{SAIFI,urban}}}$

13. $P_{\text{SAIFI,urban}} = P_{SAIFI} \times \frac{\text{ir}}{ir_{SAIFI,CBD}+ir_{\text{SAIFI,urban}}}$

14. $SAIFI_{CBD} = \frac{P_{\text{SAIFI,CBD}}}{ir_{\text{SAIFI,CBD}}} = \frac{P_{SAIFI}}{ir_{\text{SAIFI,CBD}}+ir_{\text{SAIFI,urban}}}$

15. $SAIFI_{Urban} = \frac{P_{Urban}}{ir_{\text{SAIFI,urban}}} = \frac{P_{SAIDI}}{ir_{\text{SAIFI,CBD}}+ir_{\text{SAIFI,urban}}}$

16. $SAIFI_{CBD}$=$SAIFI_{Urban}$

Similarly, SAIFI annual performance targets for CBD and urban networks require the same adjustment as below:

17. $\frac{1}{y_n} SAIFI_{CBD}= \frac{1}{Y_n} \frac{P_{SAIFI}}{ir_{\text{SAIFI,CBD}}+ir_{\text{SAIFI,urban}}} =\frac{1}{Y_n}\frac{0.4P}{ir_{\text{SAIDI,CBD}}+ir_{\text{SAIDI,urban}}}$

Note: $SAIFI_{CBD}$ and $SAIFI_{Urban}$ refer to the adjustment amount of the SAIFI targets where the reward or penalty exceeds the revenue cap.