IPART
Independent Pricing and Regulatory Tribunal
New South Wales

REVIEW OF THE DISTRIBUTION RELIABILITY STANDARDS

Draft Report

October 2020

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The Independent Pricing and Regulatory Tribunal (IPART)

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Invitation for submissions

IPART invites written comment on this document and encourages all interested parties to provide submissions addressing the matters discussed.

Submissions are due by 20 November 2020

We would prefer to receive them electronically via our online submission form.

You can also send comments by mail to:

Review of distribution reliability standards
Independent Pricing and Regulatory Tribunal
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Late submissions may not be accepted at the discretion of the Tribunal. Our normal practice is to make submissions publicly available on our website as soon as possible after the closing date for submissions. If you wish to view copies of submissions but do not have access to the website, you can make alternative arrangements by telephoning one of the staff members listed above.

We may choose not to publish a submission - for example, if it contains confidential or commercially sensitive information. If your submission contains information that you do not wish to be publicly disclosed, please indicate this clearly at the time of making the submission. However, it could be disclosed under the *Government Information (Public Access) Act 2009* (NSW) or the *Independent Pricing and Regulatory Tribunal Act 1992* (NSW), or where otherwise required by law.

If you would like further information on making a submission, IPART's submission policy is available on our website.

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1 Executive Summary

The Independent Pricing and Regulatory Tribunal of NSW (IPART) is reviewing the reliability standards in the operating licences of the state's three electricity distributors – Ausgrid, Endeavour Energy and Essential Energy (the distributors).

This report sets out our draft findings and recommended changes to the reliability standards to apply from 1 July 2024, and explains the analysis that supports them. It also seeks stakeholder feedback, which we will consider before making our final recommendations to the NSW Premier and Minister for Energy and Utilities (Minister).

1.1 Overview of draft findings and recommended changes

We found that changes to the current reliability standards are required to improve their consistency and complementarity with the national reliability incentives, and better reflect the values customers place on reliability. In addition, new standards are required to create stronger incentives for the distributors to continue to evolve and adopt new technologies to meet customers' needs through cost-effective reliability solutions. Over time, these changes to the reliability standards would lead to lower costs for distributors and deliver bill savings to customers.

In particular, we are recommending the following changes:

- **Remove network overall reliability standards that are duplicated** by national incentives for the distributors to maintain and improve reliability.
- **Update individual feeder standards and direct connection standards** so the minimum level of reliability required from each feeder/direct connection better reflects its long-term efficient level of reliability.
- **Replace customer standards with guaranteed service levels (GSLs) and payments**, and update these levels and payment amounts to better acknowledge the poorer reliability levels received by the worst-served customers on each network.
- **Introduce distributed energy resources (DER) reporting standards** to complement national efforts to efficiently increase the distributors' ability to host DER and allow greater levels of DER export to the network.
- **Introduce standalone power systems (SAPS) standards for distributor-led SAPS** and amend NSW and national energy laws to ensure these SAPS customers receive the same customer protections as the distributors' other residential and business customers.
- **Streamline the distributors' reporting and auditing requirements** to reduce their compliance and reporting costs.

1.1.1 Several changes to the standards are needed

We consider that changes to the standards are required to better strike the right balance between the costs that distributors incur to meet the standards and the value that customers place on this level of reliability.

The reliability standards play a key role in ensuring customers receive a reliable, continuous supply of electricity. For example, they require the distributors to ensure that unplanned interruptions to supply do not exceed specified levels (see Box 1.1).

However, the reliability standards are also a key driver of the costs of electricity supply. Over the past decade, the distributors' significant investments in their NSW networks were partly driven by the relatively high reliability standards at that time. The costs of these investments were passed on to customers through higher electricity bills.

In undertaking the review, we are required to consider the matters set out in the terms of reference issued by the Premier (see Appendix A). In particular we have been asked to evaluate how a distributor's efficient costs vary with different levels of reliability based on an economic assessment, and compare the costs of providing these different levels of reliability to the values customers place on reliability. We are also to have regard to several matters, including:

- The differences in the costs and benefits of delivering reliable network services to the three different networks and to different parts of these networks (including CBD, rural, and regional areas)
- Any changes to the standards that would assist the distributors to evolve and take advantage of new technologies that may offer more cost-effective reliability solutions than traditional network investments (such as distributed energy resources and standalone power systems), and
- The need for consistency with national reliability incentives and obligations, which have been introduced since the distributors' operating licences commenced.

We are recommending several changes to the standard that incorporate these matters, set out in the sections below.

1.1.2 Remove overall reliability standards duplicated by national incentives

As Box 1.1 outlines, the distributors' current licences include four categories of reliability standards that provide incentives for them to maintain and improve reliability at the overall network, individual feeder, individual direct connection, and individual customer level. These standards were introduced at a time when the licences were the primary instrument driving reliability performance.

Box 1.1 Current categories of reliability standards

Network overall reliability standards that require the distributors to ensure that the average duration and frequency of outages over their whole network do not exceed specified levels.

Individual feeder standards and individual customer (or direct connection) standards[a] that require the distributors to:

- ensure that the average duration and frequency of outages on each feeder/direct connection do not exceed specified levels
- monitor performance of individual feeders/direct connections and consider whether it is economically feasible to improve performance on those failing to meet the required standard
- report to the Minister where they determine it is not feasible to bring performance up to the required standard.

Customer service standards that require the distributor to ensure that the average duration and frequency of outages to individual customers do not exceed specified levels over a year, and provide for customers to apply for a payment of $80 for each time their distributor does not meet the required standard.

a Some large industrial customers are directly connected via sub-transmission feeders.

The NSW distributors' networks have been previously built with a high degree of redundancy which delivers a high level of reliability. The AER has developed a comprehensive incentive framework that seeks to create financial incentives for distributors to deliver distribution services at least cost and to deliver an efficient level of reliability that reflects the value customers receive from consuming electricity. It is the AER's incentives that over time should ensure customers only pay for the least cost delivery of providing distribution services that reflect the efficient level of reliability

In principle, IPART considers that state-based regulation, like the distributors' licences, should complement not duplicate national regulation. We found the AER's incentives framework provides adequate incentive to maintain and improve overall network reliability, and the network overall reliability standards in the current licences duplicate this incentive and provide no additional benefits to customers. Therefore, we are recommending the network overall reliability standards be removed from the licences.

The AER's framework does not provide incentives related to the reliability performance of individual feeders or direct connections within the network, or to the reliability levels provided to individual customers. Therefore, the licences should continue to include these reliability standards.

1.1.3 Change individual feeder standards to better reflect long-term efficient reliability levels

The current individual feeder standards use the average duration of supply interruptions (SAIDI) and average frequency of supply interruptions (SAIFI) to measure reliability. Each distributor's feeders are allocated to one of four categories – CBD Sydney, urban, short rural and long rural (see Box 1.2). Each category has different minimum required levels of reliability, and the required levels for the urban, short rural and long rural categories vary across distributors. The standards require the distributors to monitor the performance of individual feeders against the relevant standards, and to investigate the economic feasibility of improving the reliability of feeders failing to meet those standards. Where they find it is not feasible to bring a feeder's performance up to the required standard, they must report this to the Minister.

Box 1.2 Current feeder categories

The current standards and the national reliability guidelines specify four categories of feeder based on maximum demand per km and feeder length:

- **CBD Sydney:** feeders that form part of the triplex 11kV cable system supplying predominantly commercial high-rise buildings within the City of Sydney.
- **Urban:** a feeder with actual maximum demand per total feeder route length greater than 0.3 MVA/km and which is not a CBD Sydney Feeder.
- **Short rural:** a feeder with a total feeder route length less than 200 km, which is not a CBD feeder or urban feeder.
- **Long rural:** a feeder with a total feeder length greater than 200 km, which is not a CBD Sydney feeder or an urban feeder.

Source: AER's Distribution Reliability Measures Guideline, November 2018.

Note: The current licences measure urban feeder MVA/km over one year as opposed to three years in the national reliability guidelines.

We found the use of SAIDI and SAIFI to measure individual feeder reliability is appropriate and should be retained. However, we are recommending minor changes to the types of interruptions excluded from SAIDI and SAIFI to improve consistency with the national reliability guidelines.

We also found the requirements related to monitoring, investigating and reporting on the reliability performance of individual feeders are appropriate and should be retained. Importantly, these requirements ensure the standards do not encourage the distributors to invest in improving feeder reliability where the benefits to customers do not exceed the costs.

However, we found that the current approach for setting the minimum required levels of reliability of individual feeders does not strike a good balance between the distributor costs and the customer benefits associated with these levels of reliability. To address this, we consider that the standards for individual feeders should reflect their long-term efficient levels of reliability. At this stage, we are:

- Recommending the minimum required levels of SAIDI for urban, short rural and long rural feeders be set to reflect the long-term efficient levels of reliability for each feeder
- Recommending the minimum required levels of SAIFI for urban, short rural and long rural feeders be set to reflect the **existing** levels of reliability for each feeder, and
- Asking Ausgrid to model the long-term efficient levels of reliability for CBD Sydney feeders and propose the minimum required levels of SAIDI and SAIFI that should apply.

Required levels of SAIDI for urban, short rural and long rural feeders

To inform our recommendations and meet our terms of reference, we estimated the long-term efficient levels of SAIDI for urban, short rural and long rural feeders. The model we used to develop these estimates balances:

- The costs of owning, operating and maintaining feeder assets to achieve a given level of reliability, and
- The dollar value of the expected unserved energy to customers at that level of reliability, based on the AER's value of customer reliability (VCR).

This modelling shows that in each of the non-CBD Sydney feeder categories, there is a strong relationship between an individual feeder's length and its long-term efficient level of reliability. Generally, the longer the feeder, the higher the efficient level of SAIDI (and the lower the efficient level of reliability). Therefore, we consider the required level of SAIDI for all non-CBD feeders should be determined based on feeder length, regardless of feeder category and distributor.

However, we do not consider this level of SAIDI should be set **in line** with our estimates of the long-term efficient level of reliability. It is reasonable to expect some year-to-year variation from this level as a result of different fault rates that cause interruptions each year and other feeder-specific factors that we have not been able to include in our modelling. Rather, we consider a feeder should only fail to meet the standard when its reliability performance is **substantially below** our estimates of the long-term efficient level.

Accordingly, we are recommending a formula for setting the SAIDI standard for individual urban, short rural and long rural feeders that is based on feeder length. The use of this formula would mean the SAIDI standard for individual feeders reflects their long-term efficient level of reliability, while still providing an appropriate margin for their performance to be below this level. Under the draft recommendation, we expect only 1% of current feeders would fail to meet the standard. This means the distributors would be required to investigate and report on a similar number of feeders as under the current standard. However, this number would include a greater variety of feeders. This is because under the current category-based standards, a longer feeder is much more likely to fail to meet the standard than a shorter feeder in the same category because they are required to meet the same standard, but the longer feeder has a higher efficient level of SAIDI than the shorter one.

The same formula would apply to all three distributors for feeders. This means that the same required minimum level of reliability would apply to feeders with similar characteristics in different parts of the state served by different distributors. For example, a 5km feeder supplying largely residential customers would have the same minimum level of reliability in Newcastle (supplied by Ausgrid) as in Wollongong (supplied by Endeavour).

While the distributors cannot immediately deliver the long-term efficient levels of reliability indicated by our modelling, we consider they should continue exploring how to move towards efficient levels, reduce costs and deliver bill savings for customers over time.

Required levels of SAIFI for urban, short rural and long rural feeders

We also consider that the required levels of SAIFI for urban, short rural and long rural feeders should reflect the long-term efficient levels of reliability. However, data limitations meant we were not able to estimate these levels for this review. The AER's VCR estimates, which are expressed in units of $/kWh, are not suited to estimating the impact on the efficient frequency of interruptions measured via SAIFI. We consider that more work should be done on measuring the value customers place on the frequency (or infrequency) of interruptions before setting a standard on this basis. This could be included in the next review by the AER of its VCR estimates.

In the interim, we have modelled actual levels of SAIFI across different feeders. Similar to SAIDI, we found there is a strong relationship between an individual feeder's length and its existing SAIFI. Therefore, we are recommending a formula for setting the SAIFI standard for individual urban, short rural and long rural feeders based on feeder length. The use of this formula would mean the SAIFI standard for individual feeders reflects their existing level of SAIFI, while still allowing an appropriate margin for their performance to vary from this level. This would mean the distributors are required to investigate the economic feasibility of improving the performance of individual feeders when their SAIFI level falls substantially below the existing level.

Required levels of SAIDI and SAIFI for CBD Sydney feeders

As with urban, short rural and long rural feeders, we consider the required minimum standards for CBD Sydney feeders should reflect their long-term efficient levels of reliability. However, because Ausgrid's CBD distribution network relies heavily on the transmission network to deliver a reliable, continuous supply of electricity, modelling these efficient levels is more complex than for the other feeder categories.

As a result, we are not recommending levels of SAIDI and SAIFI for CBD Sydney feeders at this stage. We are asking Ausgrid to develop its own model to estimate the long-term efficient levels of reliability for these feeders, and to propose the minimum required levels of SAIDI and SAIFI that should apply. We will assess its proposal and set out draft recommendations in a supplementary draft report to be released in March 2021 and invite public comments.

1.1.4 Change direct connection standards to better reflect long-term efficient reliability levels

The current individual customer standards set minimum levels of SAIDI and SAIFI for around 400 large industrial customers that are directly connected to the distributors' network by sub-transmission feeders. These individual customer standards were introduced in 2018 and are currently split into two categories:

- Metropolitan with SAIDI and SAIFI set equal to the individual feeder urban levels, and
- Non-metropolitan with SAIDI and SAIFI set equal to individual feeder short rural levels.

We are recommending that the standards be renamed direct connection standards to better reflect the type of customers that they cover. In addition, we consider that the minimum levels of SAIDI and SAIFI should be updated to reflect our modelling of long-term efficient levels of SAIDI and actual levels of SAIFI.

Since we are no longer recommending different standards for urban and short rural feeders, there is no equivalent feeder type to align metropolitan and outer metropolitan feeders. Rather, we are recommending one direct connection standard for all areas, using the same formula for SAIDI and SAIFI individual feeders but using a 'proxy' feeder length of 1 km. This results in a SAIDI and SAIFI direct connection standard for all areas that is similar to the existing non-metropolitan standard.

1.1.5 Replace current customer standards with guaranteed service levels and payments

The current customer standards provide for eligible customers to apply for a payment of $80 each when they experience very long or very frequent outages over a year. However, very few customers apply for the payment, and its structure and level has not been updated since it was first reviewed in 2003.

We consider that the current customer service standards should be replaced with guaranteed service levels and payments. The GSLs should reflect a minimum level of acceptable reliability, and the GSL payments should act as a proxy for a refund when this level is not met. Our draft recommendations reflect that a refund is a common remedy for not meeting service obligations and also ensures that payments are linked to distributor costs which change over time.

We are recommending two levels of payments, summarised in Table 1.1. Based on the distributors' current reliability performance, around 1% of customers could receive the first payment, which would be roughly equal to the distribution network **service** charge included in their annual electricity bills. Around 0.1% of customers could receive the second payment, which would be roughly equal to the distribution network **usage** charge included in their annual electricity bills.

Table 1.1 Recommended guaranteed service levels and payments ($2020-21)

Customer service standard	Ausgrid	Endeavour Energy	Essential Energy	Payment
Level 1	15 hours, or 8 outages	15 hours, or 8 outages	20 hours, or 10 outages	Equal to the distribution network service charge in each network. For residential customers this would be around $152-$336 depending on network area.
Level 2	40 hours, or 20 outages	40 hours, or 20 outages	60 hours, or 30 outages	Equal to the distribution network usage charge in each network. For residential customers this would be around $205-$410 depending on network area.

We consider that these GSLs and payments should apply to all customers supplied under the deemed standard connection contract. These contracts cover most customers on distributors' networks. We do not consider they should apply to large customers that enter into negotiated contracts with a distributor. These businesses should be well placed to negotiate their minimum service levels (and associated capital contributions on connection). We are seeking feedback on whether the GSL payments should apply to small customers on negotiated contracts and how to best balance customer protection and innovation for these customers.

We are recommending GSL payments be made to eligible customers on application, consistent with the current approach. While an automatic payment would provide a stronger incentive for the distributors to improve performance to their worst-served customers, we consider that a payment made on application is more consistent with the principle of a refund for poor performance. An automatic payment would also be more difficult and costly for the distributors to administer, and in some cases payments would be made to customers who were not affected by the outages (eg, if they occurred late at night or when the customers were not home).

We are also recommending that the distributors develop more effective approaches to inform their customers about these payments, and be required to report on the number of customers eligible for GSL payments as well as the number who applied for them.

1.1.6 Introduce distributed energy resources reporting standards

DER refers to the broad range of technologies that operate behind a customer's meter and are capable of offsetting or shifting their demand from the grid. For example, it includes:

- Generation technologies, such as rooftop solar, wind turbines, biofuels and diesel generators,
- Demand response technologies that shift or curtail the use of certain household appliances such as pool pumps, hot water systems and air conditioners, and
- Storage technologies, including batteries, thermal storage and electric vehicle (EV) charging.

We found that the growing rate of DER is posing challenges for the distributors. While the current extent of these challenges is modest compared to those in other states, we expect this to increase in the future as take up of behind-the-meter technologies continues.

Several reform processes aimed at efficiently integrating DER into the energy market are currently underway at the national level. These include the Australian Renewable Energy Association's Distributed Energy Integration Program and the AER's DER integration expenditure consultation. In addition, the Australian Energy Market Commission (AEMC) is considering three proposed rule changes related to updating the national regulatory framework to reflect the customers' expectation for distributors to efficiently provide export services to support DER.

Given these national processes are not yet completed, we are recommending a new DER reporting standard that would require the distributors to disclose information relevant to the quality of service provided to DER customers. This would provide more data about the impact of export constraints on customers, which could then inform future decisions on whether any supplementary regulatory changes are required at either the national or state level.

1.1.7 Introduce standalone power systems standards for distributor-led SAPS

A SAPS is an electricity supply arrangement that is not physically connected to the national grid.[1] Recent developments in solar and battery technology mean that SAPS can provide cost-effective and reliable alternatives for distributors to supply electricity to their customers, particularly in high-cost parts of the network.

SAPS are not currently covered by the distributors' operating licences or the national economic regulation framework. However, the AEMC has developed a regulatory framework that, when implemented, will mean that distributor-led SAPS are treated as an extension of the traditional distribution network. We understand the NSW Department of Planning, Industry and Environment is currently considering amendments to NSW legislation to incorporate distributor-led SAPS into the distributor licensing framework.

Although distributor-led SAPS are not common in NSW, we expect their use to increase as the legislative frameworks accommodate them, and new technology improves their efficiency and competitiveness with the traditional network infrastructure.

We consider that customers of distributor-led SAPS should receive the same customer protections afforded by the licence as other residential and business customers of the distributors. This is particularly important as distributors could move customers from the network to a SAPS without their explicit consent. Therefore, we are recommending that:

- The individual feeder standards apply to microgrids with high voltage distribution lines.
- The individual feeder standards with a default length of 200km apply for all other SAPS
- The guaranteed service levels and GSL payments apply to all SAPS customers on a deemed standard connection contract.

1.1.8 Streamline distributors' annual reporting and auditing requirements

We are recommending our changes to the reliability standards take effect from 1 July 2024, to align with the beginning of the next regulatory control period. This timing would ensure both the distributors and the AER can take the revised standards into account in the next regulated revenue review. It would also give the distributors time to engage and consult with their customers on what the changes might mean for services and prices, to inform their next regulated revenue submission to the AER. We are also recommending the standards be reviewed every five years, to inform each five-year regulatory control period.

However, in the case of DER reporting standards, we consider there are benefits to the distributors providing the required information from earlier than 2024. Therefore, we recommend that the distributors commence publishing this information on a voluntary basis from 1 July 2021 until such a time that the licence is updated to reflect these requirements.

1 The term is used to cover both microgrids, which supply electricity to multiple customers, and individual power systems, which relate only to single customers. For more information see AER, Final Report: Review of the Regulatory Framework for stand-alone power systems - Priority One

We also consider there is scope to streamline the distributors' reporting and auditing requirements. They are currently required to provide quarterly reports to IPART on their compliance with the reliability standards and undertake annual independent audits of this compliance. To ensure that the costs of reporting and auditing are commensurate with the benefits, we are recommending the licence conditions be amended to require annual reports on compliance and to give IPART the discretion to decide on the frequency and scope of audits based on reported reliability performance.

1.2 Our process for the review

As part of our review to date, we have collected information, conducted public consultation, and done detailed analysis:

- In March 2020 we released an Issues Paper that set out our proposed approach for the review and sought stakeholder feedback. We received 10 submissions in response to this paper.
- We undertook further consultation and obtained additional information from the distributors to develop our modelling approach.
- We met with other key stakeholders such as the AER, AEMC, Public Interest Advocacy Centre (PIAC) and Energy and Water Ombudsman of NSW (EWON).
- We engaged HoustonKemp to provide expert advice on the interaction between national incentives and licence conditions on the distributors' reliability outcomes and incentives to efficiently incur DER export expenditure. Both of HoustonKemp's reports are available on our website.

Table 1.2 sets out an updated timetable for the review.

Table 1.2 Review timetable

Key milestone	Updated timing
Release Draft Report	22 October 2020
Public Hearing	2 November 2020
Submissions to Draft Report due	20 November 2020
Provide Final Report to Premier and Minister	December 2020
Release Draft Supplementary Report on Sydney CBD	March 2021
Provide Final Supplementary Report on Sydney CBD to Premier and Minister	May 2021

1.3 How you can have your say

We are seeking written submissions on this Draft Report and encourage all interested parties to comment on the draft findings and recommendations that it discusses, or any other issue relevant to the review. Page ii of this report provides more information on how to make a submission. Submissions are due by 20 November 2020. We will also hold a public hearing on 2 November 2020. Further information on the hearing is available on IPART's website.

1.4 Structure of this report

The following chapters provide more information on this review, our approach and our draft recommendations:

- Chapters 2 explains our draft recommendations on the role and objectives of the licences and what requirements need to be included to meet these objectives.
- Chapters 3 and 4 discuss our recommended individual feeder and direct connection standards, how they should be expressed, the types of events to be excluded when measuring performance, and the required minimum levels of performance.
- Chapter 5 sets out our recommended guaranteed service levels and payments.
- Chapter 6 describes how the standards should take account of DER and two-way energy flows.
- Chapter 7 discusses how the standards provide for the rollout of SAPS.
- Chapter 8 explains when any new standards should take effect, how often standards should be reviewed, and the appropriate compliance and monitoring framework.

Further background on the review and our approach is contained in Appendix B and Appendix C. An overview of our modelling approach is set out in Appendix D. We also prepared a draft of the revised licence conditions and reporting manual, which is on our website.

1.5 List of draft recommendations

23 That the distributors' licences include a DER information disclosure requirement commencing in 2021-22. 64

24 The NSW Government continue to progress legislative changes to incorporate distributor-led SAPS within the NSW Electricity Supply Act framework as well as incorporate distributor-led SAPS into the National Energy Retail Law (New South Wales), on national implementation of the AEMC's proposed legal and regulatory framework. 75

25 At the time of commencement of relevant enabling legislative changes, the proposed reliability standards should be extended to distributor-led standalone power systems as follows: 77

– the individual feeder standards to apply to microgrids with feeder-like high voltage distribution lines 77

– the individual standards with a default length of 200km to apply to all other distributor-led standalone power systems 77

– apply the guaranteed service levels and payments to distributor-led standalone power systems consistent with how they apply to grid connected customers. 77

26 In progressing legislative amendments, the NSW Government should ensure that customers of distributor-led SAPS receive the same customer protections afforded by the licence as other residential and business customers of the distributors. 77

27 That the recommended licence conditions come into force on 1 July 2024. 80

28 That the distributors provide annual reports to IPART on their compliance with reliability standards, with flexibility for IPART to adjust report timing through its reporting Manual If IPART considers more or less frequent reporting is appropriate. 81

29 That the distributors continue to complete quarterly investigations of individual feeders and direct connections that do not meet the SAIDI and SAIFI standards, and report these to IPART annually. 81

30 That the licence conditions allow IPART as the licence administrator, the discretion to determine the frequency and scope of independent compliance audits, and that the Tribunal does this using a risk-based approach. 81

IPART seeks comment on the following:

1 Should the guaranteed service level apply to residential and small business that are supplied on negotiated connection agreements? 54

2 Role and objectives of the licences

In reviewing electricity distribution reliability standards we first considered the role and objectives of the licences in regulating reliability. We had regard to how the drivers of reliability have changed over time, the distributors' historical performance against reliability standards, and the interaction between licence standards and the incentive schemes applying under the AER's regulatory framework. We then assessed two options:

1. Mandating an efficient level of reliability in the licences either through overall reliability standards, individual feeder standards or both.
2. Creating a requirement to report against a minimum or safety net level of service through the licence, with incentives for the efficient level of reliability being provided through the AER's regulatory framework.

To assist with assessing these options, we engaged HoustonKemp to provide advice on the interaction between the incentives that apply to the distributors under the existing licence standards and the AER's regulatory framework. We also asked HoustonKemp to consider how effectively the AER's framework provides incentives for the distributors to deliver efficient levels of reliability.

This chapter outlines our draft findings and recommendations on the role and objectives of the licences in regulating reliability and the standards we consider necessary to meet this role and objectives.

2.1 Overview of draft recommendations

We have found that licence standards should complement national reliability incentives. In particular, overall reliability standards that duplicate national incentives should be removed from the licences. However, individual feeder standards and direct connection standards should continue to provide a threshold for triggering an investigation and reporting requirement when minimum levels of reliability are not met.

The reliability standards in the current licences create obligations at an overall network, individual feeder and individual customer level. The standards were introduced when the licences were the primary instrument driving the reliability performance of the distributors. However, since then the AER has introduced a comprehensive regulatory framework, which is intended to balance incentives to reduce expenditure while maintaining or improving service quality based on the value customers place on reliability.

We consider that the licences should complement and not duplicate national incentives. Given that the AER's framework already provides an overall reliability incentive, maintaining similar standards in the licences would duplicate this incentive and provide no additional benefits to customers. Therefore, we have made a draft recommendation that the overall network reliability standards are removed from the licences.

The licences should protect customers from potential low levels of reliability by maintaining individual feeder standards, direct connection standards and guaranteed service levels and payments. Under the AER's regulatory framework, individual customers may experience very low levels of reliability that do not reflect those customers' value of reliability.

Draft Recommendations

1 That the licences should maintain individual feeder standards, direct connection standards (for larger customers) and guaranteed service levels and payments. The licence should no longer include overall feeder standards.

2 That the AER considers any imbalance in incentives between the Service Target Performance Incentive Scheme (STPIS), the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) when it next reviews the schemes.

2.2 How have the drivers of reliability changed over time?

Historically the licences were the primary instrument driving the reliability of the distributors' networks. The licences used a deterministic approach to set reliability standards, which was not linked to customers' willingness to pay.[2] However, the AER now implements a regulatory framework that is designed to provide incentives for efficient total expenditure by the distributors, that is, where benefits are greater than costs. Given the AER's regulatory framework, stakeholders have questioned the need for overall reliability standards in the licence.[3]

2.2.1 The AER's incentive schemes now drive reliability

As set out in Appendix B, the AER determines distributor revenues and incentivises distributors to achieve efficient levels of reliability, in particular through the STPIS. The STPIS operates by:

- Setting an overall performance standard or target for each feeder-type. This is usually a 5-year average of past performance.
- Adjusting a distributor's revenue by the value of customer reliability for its performance against the standard.

The STPIS works with incentives around operating and capital expenditure to balance the value of customer reliability against total expenditure. In particular, the STPIS is off-set by operating expenditure (EBSS) and capital expenditure (CESS) incentive schemes (see Box 2.1). The AER designed these schemes to balance, such that a distributor should only receive a net increase in revenue where a reliability improvement provides a net benefit (ie, a value of customer reliability greater than the costs incurred to deliver it).

The financial incentives created by STPIS can be up to ±5% of distributor revenue. For the 2019-24 regulatory period this means STPIS rewards or penalties could be up to:

- $68 million per year for Ausgrid,

2 Appendix B explains the reliability requirements under the licences and the distributors' historic performance against them.

3 See section 2.2.2 below.

- $39 million per year for Endeavour Energy, and
- $47 million per year for Essential Energy.[4]

We note that the licences can also impose penalties for breaching standards (but no rewards for exceeding standards). Penalties for breaching the licence include directions to improve performance, fines and licence cancellation.

Box 2.1 The AER's incentive schemes

The STPIS

The AER applies a STPIS to regulated network businesses (including the NSW distributors). The scheme offers incentives for network businesses to improve their service performance to levels valued by customers. It provides a counterbalance to the efficiency benefit sharing scheme (below) and capital expenditure sharing scheme [below] by ensuring network businesses do not reduce expenditure at the expense of service quality.

A distributors' revenue is increased (or reduced) based on its service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5 per cent of a distributor's revenue.

The Efficiency Benefit Sharing Scheme

The AER also applies an efficiency benefit sharing scheme (EBSS), which aims to share the benefits of efficiency gains in operating expenditure between distributors and their customers.

The EBSS allows a network business to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to five years (depending on when the spending occurs). In the longer term, network businesses can retain 30 per cent of efficiency savings (in present value terms), but must pass on the remaining 70 per cent (as lower network charges) to customers. Although we note that the actual incentive rate under the EBSS (and STPIS) reflects the way gains and losses are shared between the distributor and customers and, in particular, the length of time gains or losses are held by the distributor and the prevailing discount rate.

The Capital Expenditure Sharing Scheme

The AER's capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within the forecast levels approved in their regulatory determination. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

The CESS allows a network business to retain underspending against the forecast for the duration of the current regulatory period (which may be up to five years, depending on when the spending occurs). In the following regulatory period, the network business must pass on 70 per cent of underspends to its customers as lower network charges. The business retains the remaining 30 per cent of the efficiency savings (in present value terms).

Source: AER State of the Energy Market 2020, June 2020, Boxes 3.4, 3.5 and 3.6

4 AER's Post-tax Revenue Models (available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f%5B0%5D=field_accc_aer_sector%3A4&f%5B1%5D=field_accc_aer_segment%3A10&f%5B2%5D=field_accc_aer_region%3A14 (accessed 12 October 2020)) and IPART calculations. Figures in $2018-19, rounded to the nearest million.

2.2.2 Stakeholders question the need for overall reliability standards in the licence

In our Issues Paper we identified that the licences have an overall reliability standard that is very similar in format to the STPIS target (ie, with reference to SAIDI and SAIFI by feeder type). We sought comment on the licence's role and asked stakeholders:

- What role do licence reliability standards play in reliability regulation?
- Should we minimise duplication between NSW and the national regulatory framework?

In submissions to our Issues Paper distributors noted that the AER's STPIS is the primary overall reliability incentive and drives their behaviour more than the licence. Distributors considered that overall standards should be removed from the licence, eg, Essential Energy submitted that:

> The SAIFI and SAIDI standards for Urban, Short-rural and Long-rural feeders are already specified in STPIS, are significantly tighter than the NSW overall reliability standards, and are linked to an incentive framework. The removal of this Schedule 2 from the NSW licence conditions would remove a level of potential redundancy and additional reporting.[5]

Ausgrid considered that:

> Duplication that distorts the incentives for networks to make efficient investment and operational decisions in the NER framework should be avoided. This is best achieved by the licences maintaining a 'safety net' level of minimum reliability for customers.[6]

Distributors generally agreed that our current review should consider how licence reliability standards could provide a 'safety net' for the worst served customers. Essential Energy submitted that:

> Essential Energy, however, believes that Schedule 3 which covers individual feeders standards, and Schedule 8 for individual customer standards are important and should be retained, as these standards are not replicated in the national framework. The reporting against these standards provides a concrete measure of when customers are receiving poor reliability and allows DNSPs to target investment where it is feasible to improve performance, it also allows DNSPs to justify circumstances where rectification is not economically feasible – e.g. the cost to rectify is excessive.[7]

Endeavour Energy stated that:

> In our view, the review should focus on providing a 'safety net' level of reliability to these individual customers for whom the STPIS provides limited protection.[8]

5 Essential Energy, Submission to IPART Issues Paper, May 2020, p 12.
6 Ausgrid, Submission to IPART Issues Paper, May 2020, p 25.
7 Essential Energy, Submission to IPART Issues Paper, May 2020, p 12.
8 Endeavour Energy, Submission to IPART Issues Paper, April 2020, p 14.

This was also the position of the ENA, which submitted that:

> There are national assessment frameworks and ongoing national processes that IPART should be cognisant not to duplicate and should instead leverage off in order to deliver value to customers
>
> Minimum standards for reliability should be maintained in jurisdictional licence conditions while the AER's STPIS framework should be utilised to reveal the efficient level of reliability.[9]

We consider that it is important to take stock of all of the reliability incentives that apply to the distributors and whether incentives best sit within the licences or within the AER's regulatory framework. This is discussed in the sections below.

2.3 How do the reliability standards interact with incentive schemes?

We sought advice from HoustonKemp on the interaction between the incentives that apply to the distributors through the licence standards and the AER's reliability and expenditure schemes. We also asked HoustonKemp to consider how effective the AER's schemes are at providing incentives for the distributors to provide efficient levels of reliability.

HoustonKemp's report is available on our website and its findings are summarised in Box 2.2 below. HoustonKemp's key finding was that the best outcome is to not mandate a level of reliability in the licences but for the AER to continue to develop its incentive schemes. This should incentivise efficient levels of reliability and ensure that efficient price and service outcomes are aligned with the long-term interests of consumers.

9 ENA, Submission to Issues Paper, April 2020, p 1.

Box 2.2 HoustonKemp's report on national incentives

HoustonKemp's main recommendation was that:

- the NSW Government] not mandate a level of reliability in the NSW licences but to allow the AER to develop its incentive mechanisms to better [incentivise efficient levels of reliability.

HoustonKemp found that licence standards are asymmetric. Where the standard requires:

- A less reliable network, the businesses do not have to change practices to meet it.
- A more reliable network, the businesses have to invest to meet the standard.

Where IPART can correctly identify the efficient level of reliability (and that is more reliable than the existing performance), the licence can ensure the efficient level is met, and customers receive 100% of the benefit. However, where IPART does not correctly identify the efficient level of reliability, the licence would incentivise inefficient expenditure. HoustonKemp identified that the efficient level of reliability likely varies over time.

In contrast, HoustonKemp identified that the AER's regulatory framework sends signals to businesses that are responsive to changes in the costs of providing reliability. The AER designed its service target performance incentive scheme (STPIS), efficiency benefit sharing scheme (EBSS) for operating expenditure and capital expenditure sharing scheme (CESS) to work together to allow distributors to benefit from improving the efficiency of reliability. This is both:

- Increases to reliability – the STPIS payments are higher than the EBSS or CESS penalties
- Decreases to reliability – the EBSS or CESS payments are higher than the STPIS penalty.

Source: Houston Kemp, *Interaction between incentives and licence conditions on the reliability outcomes of distributors*, June 2020.

HoustonKemp found that, due to reductions in the underlying cost of capital over time, the incentive rates under the STPIS, EBSS and CESS are no longer the same,[10] giving distributors a stronger incentive to reduce capital expenditure relative to reliability and operating expenditure.

Under the National Electricity Rules (NER) the AER is required to have regard to interactions between the incentive schemes. We recommend that the AER considers the imbalance in incentives and the need to adjust incentive rates when it next reviews the schemes. We note that the AER recently indicated that it is currently scoping a broad review of its incentive schemes.[11]

10 That is, a distributor still retains 30 per cent of any efficiency savings or underspending of capital expenditure compared to forecast. However the recent falls in the discount rate have lowered the effective incentive rates provided by the EBSS and STPIS.

11 AER, *Draft Decision - Jemena Distribution Determination 2021 to 2026 - Attachment 9 Capital expenditure sharing scheme*, September 2020, pp 8-9.

2.4 Should the licences mandate an efficient level of reliability or a minimum level?

In our view the licences should complement, and not duplicate, the AER's regulatory framework. We considered two options:

1. Mandating an efficient level of reliability in the licences, either through overall reliability standards, individual feeder standards or both.
2. Creating a requirement to report against a minimum or safety net level of service through the licence, with incentives for the efficient level of reliability being provided through the AER's regulatory framework.

We also had regard to the views of stakeholders and the work undertaken by HoustonKemp.

The AER's regulatory framework is intended to balance incentives to reduce expenditure while maintaining or improving service quality. A distributor's revenue varies with the value customers place on reliability changes and the costs of making such changes. Distributors can maximise revenue by delivering reliability improvements where the costs are less than the value to customers. Over time, the framework provides incentives for a distributor to deliver an efficient level of reliability on average across its network.

Using the licences to try and create the same incentive would duplicate these incentives, with no additional benefit to customers. In addition, the licence is static, whereas the AER's regulatory framework changes over time (incorporating changes to the distributors' costs and updated estimates of the value of customer reliability).

We consider that the AER's regulatory framework is adequately incentivising an efficient level of reliability and that there is no need duplicate this outcome in the licences. This view is consistent with submissions from stakeholders and the report by HoustonKemp. We have made a draft recommendation to remove overall reliability standards from the licences, as appropriate incentives are provided by the AER's regulatory framework.

However, we note that the purpose of the AER's incentive schemes is to drive efficiency, not to provide a minimum or 'safety net' level of service. The application of STPIS considers existing reliability, the value of customer reliability (on average across the network) and the costs of providing distribution services. Therefore, where it is efficient, distributors could receive rewards under STPIS for achieving higher reliability on average, but at the same time some individual customers' reliability could be very low.

We consider that the role and objective of the licences should be to create a requirement to report against a minimum level of service. This position is supported by the distributors. Therefore, we recommend that the licences continue to set reliability standards. The reliability standards should target the delivery of a minimum level of service.

2.5 What licence standards are needed to target a minimum level of service?

We consider that overall reliability standards are no longer necessary, but that individual feeder standards, direct connection standards and guaranteed service levels are still required. The existing licences includes four types of reliability standards:

1. Overall reliability standards, which require the distributors to ensure that the average duration and frequency of unplanned interruptions over the network do not exceed specified levels. These overall standards apply to different feeder types (ie, Sydney CBD, urban, short-rural and long-rural feeders).
2. Individual feeder standards, which are set for each feeder type and require the distributors to investigate and report on individual feeders where the average duration and frequency of unplanned interruptions on a feeder do not meet the specified levels.
3. Direct connection standards, which require the distributors to investigate and report where the average duration and frequency of unplanned interruptions for large customers that are directly connected to the sub-transmission network do not meet the specified levels.
4. Guaranteed service levels, which provide for eligible customers to apply for a payment where the distributor exceeds the customer interruption duration and/or frequency standard.

As discussed above, we have made a draft recommendation to remove overall reliability standards from the licences, as appropriate incentives are provided by the AER's regulatory framework to drive distributors to the efficient level of reliability. We discuss the other types of standards below.

2.5.1 Individual feeder standards provide an important level of customer protection

The individual feeder standards apply to each individual feeder rather than being averaged across a feeder type (as is the case with overall reliability standards). The distributors are required to monitor the performance of individual feeders, consider whether it is economically feasible to improve performance on feeders failing to meet the standard and report where they determine that it is not feasible to bring performance up to the required standard.

We consider that individual feeder standards provide an important level of customer protection through:

- Requiring distributors to investigate how to improve reliability on a non-compliant feeder.
- Requiring investment to improve reliability on that feeder where economic.

This effectively focuses the distributor's attention to improving reliability to where it is most needed. Without the individual feeder standards the distributor may choose to invest its funds in other projects (eg, with a higher rate of return), while continuing to provide low levels of reliability even where it is economic to provide a more reliable service.

If individual feeder standards are set at a minimum satisfactory level of reliability this will ensure that each feeder will meet this standard or, if it does not, the distributor will investigate the costs and benefits of action and improve reliability where it is economic to do so.

Chapters 3 and 4 explain how we have set individual feeder standards.

2.5.2 Direct connection standards fill a gap in reliability regulation

The licence also includes direct connection standards, which only apply to customers not connected to a feeder. These are typically very large customers that are connected directly to the high voltage or sub-transmission network.

Individual feeder standards, overall feeder standards and the STPIS do not apply to these customers' connections. Therefore direct connection standards fill a gap in reliability regulation. Direct connection standards operate similarly to individual feeder standards, with additional reference to the customer's contract.[12] We consider that the licences should retain direct connection standards.

2.5.3 Guaranteed service levels fill the gaps in individual feeder standards

To meet an individual feeder standard a distributor has to provide sufficient reliability to meet the standard on average across the feeder.[13] Therefore, a distributor can comply with its individual feeder standards while providing some customers very low levels of reliability.

To set an individual customer standard (for feeder-connected customers) would require customers to have smart meters, so that distributors can identify which customers have outages and for how long. In NSW the majority of customers do not have smart meters.

The guaranteed service levels do not operate like the other reliability standards. The licences do not require the distributors to report on how many times they have breached the guaranteed service levels. Instead the licences require that the distributors:

- Take reasonable steps to make customers aware of guaranteed service level payments.
- Pay customers a guaranteed service level payment where customers apply for the payment and the standard has been breached.

The guaranteed service level payments operate more as an acknowledgement of providing low levels of service.

We consider that the licences should retain guaranteed service levels and payments. They provide a mechanism for customers to receive acknowledgement and payment where they receive low levels of service. This provides:

12 Other standards do not reference the customer contract as the customers covered by them do not have individually negotiated contracts.

13 The median feeder in NSW has 663 customers connected.

- An incentive for distributors to improve performance (where the costs of payments are greater than remedial works).
- A form of compensation to customers that they can use to offset the costs of electricity.

Chapter 5 explains how we have set guaranteed service levels and payments.

3 Expressing individual feeder standards and excluded events

Having decided to maintain individual feeder and direct connection standards, our next step was to consider whether any changes to these standards are necessary to better meet the role and objectives of the licences.

The main issues we considered when setting individual feeder and direct connection standards were how to express the standards, the types of events to be excluded when measuring performance and the required levels of performance.

The sections below provide an overview of our draft recommendations on how the individual feeder standards should be expressed and the types of events to be excluded when measuring performance. We then discuss the analysis which underpins these recommendations. Our draft recommendations on the levels of reliability in the standards and the reporting and investigation process that would be triggered when the levels are not met are discussed in Chapter 4.

3.1 Overview of draft recommendations

We recommend that individual feeder and direct connection standards should continue to use both the duration and frequency of supply interruptions (SAIDI and SAIFI) to measure minimum levels of reliability.

Excluded interruptions are disregarded when measuring reliability so that the distributors are not penalised for events that are generally considered beyond their control. We recommend some minor changes to the types of events to be excluded when measuring SAIDI and SAIFI in the standards. These changes will better align the standards with the national reliability guidelines and continue to provide incentives for the distributors' networks to become more resilient over time. We are also recommending further reporting around major event days (MEDs) and planned interruptions to increase visibility to customers when their reliability is impacted by these events.

Draft recommendations:

3 Individual feeder standards should continue to be defined using SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index), in line with the AER's Distribution Reliability Measures Guideline.

4 That the excluded events are aligned with the AER's Distribution Reliability Measures Guidelines and Service Target Performance Incentive Scheme (STPIS).

5 That the current approach of identifying Major Event Days using a method based on the *IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices* be maintained to encourage the networks to ensure that their networks become more resilient over time.

6 That the licence introduce a requirement for distributors to publish daily progress updates to customers on how long it takes to reconnect customers after a Major Event Day (MED)

7 That a new obligation be imposed on distributors to collate data on planned outages and publish an annual report on their websites by 31 August of each year.

3.2 What measures of reliability should be used in the standards?

Under the current licence conditions, the distributors are required to ensure that the average duration and frequency of unplanned interruptions on each feeder do not exceed specified levels. These levels are measured using System Average Interruption Duration Index (SAIDI) and a System Average Interruption Frequency Index (SAIFI).

SAIDI is calculated by summing the duration of each sustained customer interruption over a period of time and dividing it by the number of customers. It estimates the total duration of unplanned outages that a customer is likely to experience, on average. SAIFI is calculated by summing the number of unplanned sustained customer interruptions over the period and dividing this total by the number of customers. It measures the number of interruptions a customer experiences, on average.

In our Issues Paper we sought comment on whether these measures should continue to be used in the standards, defined in line with the AER’s Distribution Reliability Measures Guideline (the national reliability guidelines).

3.2.1 Stakeholders supported maintaining SAIDI and SAIFI

The stakeholders that responded to this issue supported continuing measuring reliability using SAIDI and SAIFI Ausgrid[14] and Endeavour Energy[15] noted that these metrics are well defined and widely used, which adds to their credibility.

The SAIDI and SAIFI metrics are consistent with the national reliability guidelines issued by the AER for measuring distribution network reliability.

We consider that a national framework and common set of definitions increases the transparency and consistency of distribution reliability measurements. It also:

- Allows the assessment, comparison and benchmarking of the reliability performance of all distribution businesses in the national electricity market (NEM) and
- Minimises regulatory burden by ensuring that the NSW distributors measure and report reliability performance similarly for the NSW Government and the AER.

The use of different reliability measures may result in the distributors incurring additional reporting and compliance costs and potential confusion in understanding obligations.

14 Ausgrid, Submission to Issues Paper, May 2020, p 19.
15 Endeavour Energy, Submission to Issues Paper, April 2020, p 10.

3.3 What types of events should be excluded when measuring reliability?

In our Issues Paper we noted that there are some differences between exclusions under the licence and national reliability guidelines and sought comment on whether they should be aligned. We have considered the differences between state and national incentives with a view to aligning them where appropriate. We consider that our draft recommendations to align excluded events under the licence with the AER's national reliability guidelines will reduce compliance costs and encourage the distributors to build more resilient networks. Over time, this will also lead to a reduction in electricity costs for consumers, consistent with the objective of this review.

3.3.1 Two different sets of excluded interruptions would impose unnecessary regulatory burden on the distributors

All respondents agreed with our proposal to align excluded events, with Essential Energy citing the impracticality of reporting against different sets of exclusions as a key reason to align them.[16] Ausgrid also noted that streamlining compliance efforts through aligning the excluded interruptions would ultimately promote affordability for customers by reducing regulatory reporting costs.[17] We consider that aligning the excluded interruptions will therefore balance the role of the standards and the need to reduce the regulatory burden that arises from reporting against two different sets of exclusions.

3.3.2 Excluded interruptions in the standards should be updated

Our draft recommendation is to align the NSW licence condition exclusions with those in the AER's STPIS and the proposed changes are reflected in Box 3.1 below. The italicised events are the excluded interruptions that we recommend adopting from the STPIS exclusions, to facilitate the proposed alignment.

16 Essential Energy, Submission to Issues Paper, May 2020, p 17.
17 Ausgrid, Submission to Issues Paper, May 2020, p 20.

Box 3.1 Proposed excluded interruptions - Schedule 2 to the distributors' licences

(a) In this Schedule 2:

Load shedding means reducing or disconnecting load from the power system;

System operator has the same meaning as in the *National Electricity Law (NSW)*.

(b) The following types of interruptions (and no others) are excluded interruptions:

(i) an interruption of a duration of three minutes or less;

(ii) an interruption resulting from:

(A) load shedding due to a generation shortfall;

(B) automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition described in the Power System Security and Reliability Standards made under the National Electricity Rules;

(C) *load shedding at the direction of the Australian Energy Market Operator (AEMO) or system operator*

(D) a failure of the shared transmission network;

(E) the exercise of an obligation, right or discretion imposed, or provided for, under the Act or Regulations or national electricity legislation

(iii) an interruption caused by a failure of transmission connection assets unless the interruption was due to:

(A) action, or inaction, of the Licence Holder that is inconsistent with good industry practice; or

(B) inadequate planning of transmission connections and the Licence Holder is responsible for transmission connection planning;

(iv) an interruption caused, or extended, by a direction from NSW or Federal emergency services, provided that a fault in, or the operation of, the distribution network did not cause, in whole or in part, the event giving rise to the direction;

(v) a planned interruption;

(vi) an interruption which commences on a major event day.

Source: Proposed Schedule 2 of Ausgrid, Endeavour Energy and Essential Energy licence conditions and IPART analysis.

As a result of the proposed alignment of the exclusions, some events that previously appeared in the NSW licence condition are no longer excluded or are worded slightly differently. We have summarised the proposed changes and their rationale in the table below.

Table 3.1 Proposed changes to the excluded interruptions

AER	NSW	Proposed change to NSW
Load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator.	This exclusion does exist in the current NSW licence however it is worded as a direction or other instrument issued under the National Electricity Law to interrupt the supply of electricity	Amend the wording of this exclusion in the NSW licence to align with STPIS.
Load interruptions caused by a failure of transmission connection assets except where the interruptions were due to: (a) actions, or inactions, of the DNSP that are inconsistent with good industry practice; or (b) inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.	This exclusion does not currently exist in the NSW licence conditions.	Introduce this exclusion to NSW licence as it could impact the distributor's ability to provide a reliable supply. Its meaning is also different from interruptions caused by a failure of the shared transmission network therefore it adds a necessary element that could be beyond the control of the distributors.
Load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.	This exclusion does not currently exist in the NSW licence conditions.	Introduce this exclusion to NSW licence.
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.	This exclusion does exist in the current NSW licence however it is worded as a direction or other instrument issued under the Energy and Utilities Administration Act 1987, the Essential Services Act 1988 or the *State Emergency and Rescue Management Act 1989* to interrupt the supply of electricity.	Amend the wording of this exclusion in the NSW licence to align with STPIS.
NA	An interruption caused by a customer's electrical installation or failure of that electrical installation	Remove this exclusion from NSW licence as we agree with the AER that such interruptions are capable of being controlled by the networks.

Source: Current Ausgrid, Endeavour Energy and Essential Energy distribution network licences, AER's *Electricity distribution network service providers - Service target performance incentive scheme* November 2018, IPART analysis.

3.4 How should major event days be treated?

Under the current standards, the distributors may exclude any interruption to the supply of electricity which commences on a major event day (MED). These days are excluded because they are not representative of a normal day in terms of reasonable network resource availability. They are typically caused by severe weather conditions.[18]

18 AER, Final decision Amendment to the Service Target Performance Incentive Scheme (STPIS) Establishing a new Distribution Reliability Measures Guideline (DRMG), 2018, p 18

This excluded interruption is based on the *IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices* (IEEE Standard) which recommends the use of the beta statistical method to identify MEDs.[19]

3.4.1 Excluding MEDs is consistent with the AER's STPIS

Given its use under the AER's STPIS, maintaining the current MED approach would minimise regulatory burden for the distributors as they can report consistently to the state and national regulator. The IEEE Standard's MED method has been in the licence conditions since they were issued. We consider that it has been effective in ensuring a consistent approach to excluding significant events from calculations of performance against the reliability standards.

None of the respondents to the issues paper raised concerns regarding the current MED approach however, Endeavour Energy[20] and PIAC[21] suggested that IPART consider alternative statistical approaches such as the Box Cox method. The current licence conditions allow for the distributors to seek IPART's approval to apply a different threshold, where the natural log transformation does not closely resemble a normal distribution.[22]

The AER has also considered several requests to apply different thresholds. Most recently in 2015, the AER decided to allow Endeavour Energy to use the Box Cox transformation method in determining its MEDs for the 2019-2024 regulatory period.[23] In that decision, the AER noted that it had previously approved the use of the Box Cox transformation by the Electricity Trust of South Australia (ETSA) as part of its 2010 determination.[24] We note that ETSA (now known as South Australia Power Networks), reverted back to using the Beta method in its 2015 determination.[25]

In 2017, Endeavour Energy sought our approval to use the Box Cox transformation method to identify MEDs as part of its compliance with reliability licence conditions. We considered that the Box Cox Transformation method was not appropriate as it yields results that are inconsistent with the intent of the IEEE Standard and:

- The Box-Cox transformation does not provide a normal distribution and fails three of the four tests of normality.
- Given that non-normality, Endeavour Energy had not demonstrated that the Box-Cox transformation provides a superior outcome to the natural log transformation.
- Endeavour Energy's application of the Box-Cox transformation used a different value of lambda for each year, reducing its effectiveness for establishing longitudinal reliability trends and comparisons.
- The use of the Box-Cox transformation does not align with the intent of the IEEE Standard to achieve a mean of 2.3 major event days per year.

19 IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices, pp 10-13.
20 Endeavour Energy, Submission to Issues Paper, April 2020, p 10.
21 PIAC, Submission to Issues Paper, May 2020, p 5.
22 Schedule 6 to the licence conditions of Ausgrid and Endeavour Energy.
23 AER, Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19.
24 AER, Draft decision attachment 11: Service target performance incentive scheme, November 2014, p 21–23.
25 AER, Final Decision SA Power Networks determination 2015-16 to 2019-20

We maintain the view that the Box-Cox transformation should not be used to identify MEDs.

3.4.2 Our approach to major event days drives network resilience

As the climate changes and extreme weather events become more prevalent, it is more important for customers that distributors are ready for and able to promptly recover from MEDs i.e. become more resilient.[26] The impact of the 2019-20 NSW bushfires on people, businesses and the environment was unprecedented. 5.4 million hectares[27] of land was burnt which damaged power poles and other electricity infrastructure leaving many customers without power.

Distributors are expected to build their networks to be resilient against the environment in which they operate and should be encouraged to do this where the benefits of this resilience outweighs the costs and reflect customers willingness to pay. We consider that the IEEE Standard drives and incentivises resilience as it is designed to classify a mean of 2.3 MEDs per year.[28] Over time as weather events become more extreme, the MED approach requires distributors to appropriately adapt and make sure their networks are more resilient.

3.4.3 Distributors to publish daily updates on progress to restore supply after a Major Event Day

Our draft recommendation is for distributors to publish daily updates on the restoration of electricity supply after a MED. We recommend that the distributors publish the following information as part of the progress update:

- The number of customers affected
- The number of customers restored
- Where challenges have been faced in restoring supply and
- The estimated time (by reference to hours or days) that supply will be restored.

The progress updates must be via a distributors' website and social media and must be provided at least once a day until power is fully restored to all affected customers.

Monitoring the rate of reconnections after a major event day indicates the severity of the MEDs and over time, the distributors' level of network resilience. We consider that any additional costs of implementing this change are likely to be minimal and outweighed by the benefits to customers.

26 Resilience and Reliability for Electricity Networks, CSIRO Publishing – The Royal Society of Victoria 131, pages 44-52, 2019, by Jill M Cainey.

27 NSW Fire and the environment 2019-20 summary by Department of Planning, Industry and Environment, p 5 - https://www.environment.nsw.gov.au/-/media/OEH/Corporate-Site/Documents/Parks-reserves-and-protected-areas/Fire/fire-and-the-environment-2019-20-summary-200108.pdf.

28 IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices, p 22.

3.5 Is current reporting on planned outages adequate?

Distributors are required to give consumers four days' notice of planned outages including the expected duration of the outage.[29] This requirement is in place to ensure that customers are given adequate notice of an interruption and to ensure that distributors properly planned for such outages. Depending on the frequency, duration and timing of those planned outages, customers can be inconvenienced.

While distributors report to the AER on planned outages[30] this information is not presented in a consumer friendly manner. In response to the Issues Paper, The NSW Farmers Association suggested additional reporting on planned outages.[31]

As distributors report to the AER on planned outages we would not be seeking to duplicate this effort. Instead, we propose to require that the distributor publish annually by 31 August of each year with the following information:

- the average duration of planned interruptions by reference to postcodes;
- the number of planned interruptions that exceeded the estimated duration time for the relevant planned interruptions; and
- in relation to the planned interruptions, the reasons for the interruption exceeding the estimated duration time.

3.5.1 An information disclosure requirement would not impose regulatory burden

The pie charts below are based on outage numbers and are indicative of the proportion of planned and unplanned outages in 2018-19[32]:

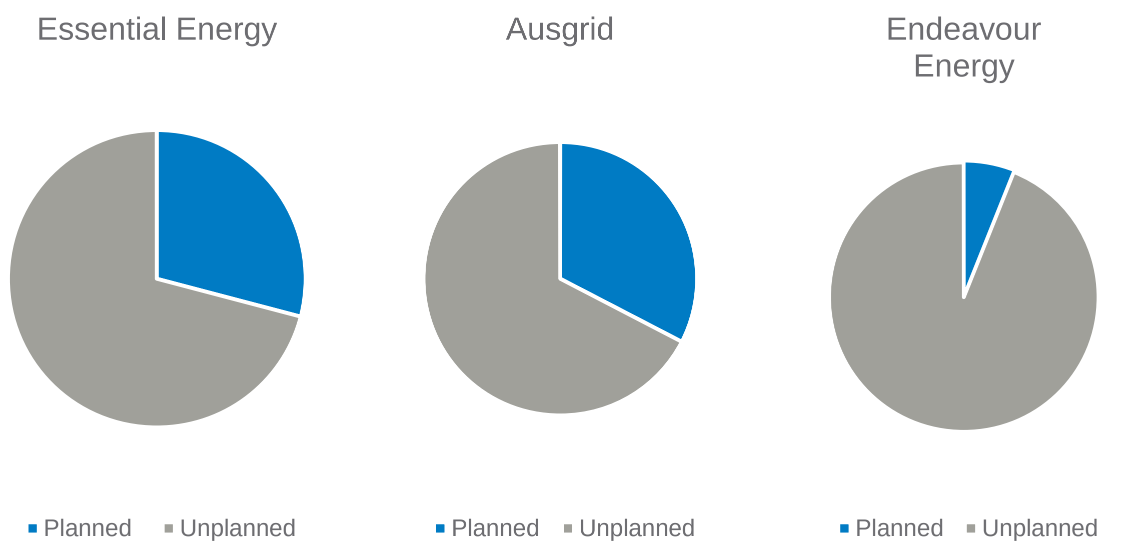
29 Rule 90 (1B) of the National Energy Retail Rules - https://www.aemc.gov.au/sites/default/files/2020-08/NERR%20v24%20full.pdf. Note that in NSW, a shorter notice period may be accepted if it is agreed in writing by the distributor and the customer.

30 Distributors report on planned interruptions to the ASRER via their Regulatory Information Notices (RINs)

31 NSW Farmers Association, Submission to Issues Paper, April 2020, p 16.

32 Based on the number of outages in the 2018 – 19 Category RIN analysis data reported to the AER.

Figure 3.1 Planned and unplanned outages 2018-19



Data source: 2018 – 19 RIN data provided by the distributors to the AER.

We do not consider that any such reporting requirement would impose undue regulatory burden on the distributors. It would simply be summarising and categorising total numbers and providing high level reasoning for planning the outages. Any additional costs associated with the reporting are likely to be minimal and outweighed by the benefits.

4 Setting individual feeder and direct connection standards

Having decided how to express the standards and the types of events to be excluded, our next step was to decide how to set the minimum levels of reliability for individual feeders and the approach to investigating and reporting on these feeders when they do not meet the standards. The sections below provide an overview of our draft recommendations on these areas. We then discuss the analysis which underpins these recommendations.

4.1 Overview of our draft recommendations

We found that the current approach for setting the minimum required levels of reliability of individual feeders does not strike a good balance between the distributor costs and the customer benefits associated with these levels of reliability. To address this, we are:

- Recommending new approaches to set the required levels of SAIDI for urban, short rural and long rural feeders (non-CBD feeders) that reflect the long-term efficient levels of reliability for each feeder.
- Asking Ausgrid to develop a model to determine the long-term efficient levels of reliability for CBD Sydney feeders and propose the minimum required levels of SAIDI and SAIFI that should apply. We will assess their proposal and set out draft recommendations in a supplementary report to be released in March 2021.

Required levels of SAIDI for urban, short rural and long rural feeders

To inform our recommendations and meet our terms of reference, we developed estimates of the long-term efficient levels of SAIDI for urban, short rural and long rural feeders. The model we used balances:

- The costs of owning, operating and maintaining feeder assets to achieve a given level of reliability
- The dollar value of the expected unserved energy to customers at that level of reliability, based on the AER's value of customer reliability (VCR).

This modelling shows that in each of the non-CBD Sydney feeder categories, there is a strong relationship between the feeder length and an individual feeder's long-term efficient level of reliability. Generally, the longer the feeder, the higher the efficient level of SAIDI (and the lower the efficient level of reliability). Therefore, we consider the required level of SAIDI for all non-CBD feeders should be determined based on feeder length only, regardless of feeder category and distributor.

However, we do not consider this level of SAIDI should be set **in line** with our estimates the long-term efficient level of reliability. As noted earlier, we consider that the purpose of the licence should be to specify minimum or safety net levels of reliability. In addition, it is reasonable to expect some year-to-year variation from this level as a result of different fault rates that cause interruptions each year and other feeder-specific factors that we have not been able to include in our modelling. Rather, we consider a feeder should only fail to meet the standard when its reliability performance is **substantially below** our estimates of the long-term efficient level.

Accordingly, we are recommending a formula for setting the SAIDI standard for individual urban, short rural and long rural feeders that is based on feeder length. The use of this formula would mean the SAIDI standard for individual feeders reflects their long-term efficient level of reliability, while still providing an appropriate margin for their performance to be below this level. Under the draft recommendation, we expect around 1% of current feeders would fail to meet the standard. This means that the distributors would be required to investigate and report on a broadly similar number of feeders as under the current standard.[33] However, this number would include a greater variety of feeders. This is because under the current category-based standards, a longer feeder is much more likely to fail to meet the standard than a shorter feeder in the same category because they are required to meet the same standard, but the longer feeder has a higher efficient level of SAIDI than the shorter one.

The same formula would apply to all three distributors. This means that the same minimum level of reliability would apply to feeders with similar characteristics in different parts of the state served by different distributors – for example a 5 km feeder supplying largely residential customers would have the same minimum level of reliability in Newcastle (supplied by Ausgrid) as in Wollongong (supplied by Endeavour).

Required levels of SAIFI for urban, short rural and long rural feeders

We also consider that the levels of SAIFI specified in the standard should be informed by the long-term efficient levels of reliability. However, the AER's VCR estimates are expressed in units of $/kWh and are better suited to estimating the impact on the efficient duration of interruptions measured via SAIDI rather than the frequency of interruptions measured via SAIFI. We consider that more work should be done on measuring the value of avoiding frequent interruptions to customers before setting a standard on this basis. In the interim, we recommend that the distributors should be required to investigate individual feeders where the SAIFI substantially differs from existing levels of performance.

As with SAIDI, we have found that there is a strong relationship between feeder length and the existing SAIFI of individual feeders. Therefore, we consider the required level of SAIFI for all non-CBD feeders should also be determined based on feeder length only, regardless of feeder category and distributor.

33 In the case of Essential Energy we expect an increase in the number of feeders.

Required levels of SAIDI and SAIFI for CBD Sydney feeders

For CBD feeders, the nature of Ausgrid's CBD network and the degree to which it relies on the transmission network to deliver a continuous supply of electricity, means that modelling long term efficient reliability is more complex. As a result, we are not recommending levels of SAIDI and SAIFI for CBD Sydney feeders at this stage. We are asking Ausgrid to develop its own modelling of long term efficient reliability for these feeders and propose the minimum levels of SAIDI and SAIFI that should apply. We will assess their proposal and set out draft recommendations in a supplementary report to be released in March 2020.

Changing direct connection standards to better reflect long-term efficient reliability levels

We are recommending that the individual customer standards be renamed direct connection standards to better reflect the type of customers that they cover. In addition, we consider that the minimum levels of SAIDI and SAIFI should be updated to reflect our modelling of long-term efficient levels of SAIDI and actual levels of SAIFI.

Since we are no longer recommending different standards for urban and short-rural feeders, there is no equivalent feeder type to maintain the current approach in the standards. Rather, we are recommending one direct connection standard for all areas, using the same formula for SAIDI and SAIFI individual feeders but using a 'proxy' feeder length of 1 km. This results in a SAIDI and SAIFI direct connection standard for all areas that is similar to the existing non-metropolitan standard.

Investigating and reporting on feeders that do not meet the standard

We also found the requirements related to monitoring, investigating and reporting on the reliability of individual feeders that do not meet the standard are appropriate and should be retained. Importantly, these requirements mean the standards do not encourage the distributors to invest in improving feeder reliability where the benefits to customers do not exceed the costs. We have retained this policy intent in our proposed licence conditions but streamlined the investigation and reporting requirements to make clearer what the distributors should do at each stage.

Draft Recommendations

8 Individual feeder standards should be set for two feeder types – **CBD Sydney** and **non-CBD**.

- **CBD Sydney** feeders are defined using the existing licence definition – that is, feeders forming part of the triplex 11kV cable system supplying predominantly commercial high-rise buildings, within the City of Sydney.
- **Non-CBD** feeders would be defined as any feeder that is not a CBD feeder and would cover all feeders in the three categories used in the existing licence and the AER's national guidelines for reliability measurement (urban, short rural and long rural).

9 Individual feeder standards for Ausgrid, Endeavour Energy and Essential Energy's **non-CBD** feeders for **SAIDI** should be set as a function of feeder length using the expression below.

$$SAIDI = 330 + 55.2\sqrt{length} + MIN(160, \frac{5500}{length})$$

This approach would require the distributors to report and investigate causes of SAIDI for feeders whose reliability is substantially worse than our estimates of long term efficient levels.

10 Individual feeder standards for Ausgrid, Endeavour Energy and Essential Energy's **non-CBD** feeders for **SAIFI** should be set as a function of feeder length using the expression below.

$$SAIFI = 3 + 0.23\sqrt{length} + MIN(0.65, \frac{21}{length})$$

This approach would require the distributors to report and investigate causes of SAIFI for feeders whose reliability is substantially worse than estimate levels of actual SAIFI.

11 Individual feeder standards for **CBD feeders** - that is, feeders forming part of the triplex 11kV cable system supplying predominantly commercial high-rise buildings, within the City of Sydney – should be set following further modelling to be provided by Ausgrid and set out in a Supplementary Draft Report to be released in March 2021.

12 Direct connection standard for all areas should be set using the same formula for SAIDI and SAIFI for individual feeders but using a 'proxy' feeder length of 1 km.

13 When reporting **non-CBD** feeders that do not meet the individual feeders standards, the distributors continue grouping them into the three feeder types set out in the national guidelines (urban, short rural and long rural).

14 Individual feeder standards require the distributors to follow the reporting and investigation process set out in Box 4.2.

4.2 How should different feeder types be defined?

To decide what feeder types to use and how to define them, we considered the current categories in the licence and national reliability guidelines and STPIS as well as the results of our modelling.

4.2.1 CBD feeders

For 'CBD Feeders', the AER has specifically given state jurisdictions the role for determining what constitutes a 'CBD Feeder'.[34] CBD feeders form part of Ausgrid's 'triplex' network which has been designed to give customers extremely high reliability and is unique to the Sydney CBD. We recommend maintaining the current definition of CBD Sydney Feeders to reflect the unique nature of this part of Ausgrid's network.

34 AER, Distribution Reliability Measures Guideline, 2018, p 6, Available from https://www.aer.gov.au/system/files/AER%20-%20Distribution%20Reliability%20Measures%20Guideline%20-%20Version%201%20-%2014%20November%202018%20%28updated%2020%20November%202018%29.pdf

4.2.2 Non-CBD feeders

For non-CBD feeders, the national reliability guidelines and existing licences specify three categories of feeder based on maximum demand per km and feeder length:

- Urban – a feeder with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km and which is not a CBD Sydney Feeder.
- Short-rural – a feeder with a total feeder route length less than 200 km, which is not a CBD feeder or urban feeder.
- Long-rural – a feeder with a total feeder length greater than 200 km which is not a CBD Sydney feeder or an urban feeder.

We have found that there is a strong relationship between feeder length and the reliability of individual feeders. For example, the longer a feeder is, the higher the level of SAIDI (and lower level of reliability). As a result, we consider that the standards should be determined based on feeder length only. This means that each feeder will have its own level of SAIDI set as a function of feeder length.

Although the licences would not specify the required level of SAIDI and SAIFI using the three categories from the national guidelines, the distributors would still be able to group feeders into these categories to aid comparison with information reported to the AER.

4.3 How did we set required levels of SAIDI for urban, short rural and long rural feeders?

To meet our terms of reference, we developed a proposed approach comprised of two main stages:

1. Modelling the efficient level of reliability across different individual feeders.
2. Developing individual feeder standards that provide the distributors with an incentive to deliver minimum levels of reliability where it is economically efficient to do so.

4.3.1 Stage 1 Modelling efficient reliability

The first stage of our approach involved developing a model to estimate the efficient amount of expected unserved energy per year for each feeder. The sections below provide an overview of the approach we used and the results of this stage.

Our approach

We engaged Nuttall Consulting to develop models for each distributor covering all non-CBD feeders (urban, short rural and long rural). The models estimate both:

- The network costs of owning, operating and maintaining feeder assets to achieve a given level of reliability.
- The dollar value to customers of the expected unserved energy at that level of reliability.

The sum of the network costs and the value of the expected unserved energy is the total social cost for a feeder at a given level of reliability.

Distributors face choices about how to design different network elements and how to restore supply after an outage. These choices affect both network costs and the likely time to restore power after an outage. The model evaluates the costs and expected unserved energy for each choice, and determines which combination of choices leads to the lowest social cost. This is the efficient level of reliability. Box 4.1 sets out further information on the modelling approach we have used.

Box 4.1 Modelling the efficient level of reliability (expected unserved energy)

Modelling the efficient level of unserved energy involved three main steps.

1. Undertaking statistical analysis of historical interruption data for each distributor to determine relationships that represent the existing average reliability performance of the feeders.
2. Setting up a network model of each feeder to reflect the existing performance statistics given by Step 1. This “set-up” is achieved by inputting properties of the feeder that are known or can be calculated (such as feeder length, proportion of overhead lines, maximum demand) and then setting network design criteria (such as the length of the feeder that is covered by some degree of redundancy) and approach to restoration and repair of faults (such as switching arrangements and time to repair) to ensure that the modelled performance reflects the performance statistics.
3. Adjusting the network design criteria, restoration and repair approach for each feeder to estimate the efficient reliability performance.

The efficient reliability performance is calculated as an allowance for expected unserved energy in kWh. Looking at the expected duration of outages, we can then convert expected unserved energy to an allowance in terms of the number of minutes per customer (SAIDI).

We have focused our modelling on the High Voltage (HV) network, as this part of the feeder has the most substantial impact on reliability. Modelling the LV network in detail would substantially increase the complexity of the task. Also, there are not as many levers available to a distributor to significantly alter the reliability performance of the LV part of the network. Therefore, we have not included LV outages in our optimisation-based estimate of the efficient reliability of each feeder. Instead, we add an allowance for current LV outages to the efficient SAIDI and SAIFI for the HV part of the network in the second stage of our approach to developing the standards.

Further detail on the approach, inputs and modelling assumptions we have used is included in Appendix D. We have consulted with each of the distributors over several workshops in developing the models. Where possible, we have used publicly available information (eg, information reported by the distributors to the AER) in our modelling. We will publish a copy of the model on our website and look forward to feedback from the distributors and other stakeholders in response to our Draft Report.

We understand that there will be differences between the modelled efficient performance of the feeder and the efficient reliability in practice. These result from, for example, specific environmental factors that will affect some feeders such that their average outage rate will be higher (or lower) than suggested by our statistical analysis or, specific network arrangements that are not fully captured by our network model. However we consider that the model provides an appropriate estimate of the reliability on average across each of the feeder types. The second stage of our approach also takes account of some of these differences.

One of the most important sensitivities in the model is the value of customer reliability (VCR). Our terms of reference require us to have regard to the AER's latest estimates of VCR. The AER has estimated VCRs for different customer types (for example, residential, industrial and commercial) in different climate zones across the state. Its final report states that a VCR estimate should be reflective of the customer composition on the network.[35] In modelling individual feeder standards, we identified VCR as a key sensitivity and asked each of the distributors to provide estimates of the VCR that reflect the customer mix on each feeder.[36]

We consider that a feeder-specific VCR is the most appropriate basis for setting individual feeder standards, as opposed to a state-wide average across all customer climate zones and all customer types. This will better reflect the mix of customers on each feeder and minimise customers being required to pay for reliability on their feeders that they do not value.

Essential Energy and Endeavour Energy provided these estimates and we have used them in our modelling. Ausgrid has not yet provided these estimates. We have developed our own estimate of VCRs for each feeder for Ausgrid and have used these in developing our draft recommendations. We expect Ausgrid to provide information on feeder-specific VCRs to inform our Final Report.

Results of efficient reliability modelling

Table 4.1 and Table 4.2 below sets out the key outputs of the model for Endeavour Energy. In general, the modelling indicated an efficient level of reliability based on a network that was less expensive to own and operate than the current network design, but imposed a somewhat higher level of expected unserved energy on customers. At current estimates of the value of customer reliability, this trade-off led to a welfare gain to society.

In specific terms, on average across all feeders, we found that the efficient level of SAIDI (indicated by the Efficient row in the table below) is higher than the existing level of SAIDI. For example urban feeder SAIDI increased from 45.4 minutes per year existing to 77.4 minutes per year efficient. Our modelling also found that these efficient levels of reliability can be delivered for a lower network cost as indicated by the reduction in total annualised costs between the "Network costs existing" and "Network costs efficient"rows in the tables below. While the distributors cannot immediately deliver these levels of reliability at a lower cost, they should consider how to move towards them when considering the replacement or growth of assets.

Note that the existing reliability and costs in Table 4.1 to Table 4.2 and 2, refer to our modelled estimates of existing reliability as opposed to actual reliability performance. Network costs include the operating and capital costs of providing that level of reliability on individual feeders only. Reliability costs are the cost to customers of the outages at that level of reliability.

35 AER, Values of Customer Reliability – Final Decision, 2019, p 9 , Available from https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

36 This requires estimates of the number of different types of customers and their demand on each feeder. This information is not publicly available.

Table 4.1 Endeavour modelled SAIDI – existing and efficient (mins per year)

Reliability	Urban	Short Rural	Long Rural
Existing SAIDI	45.4	143.0	NA
Efficient SAIDI	77.4	173.1	NA

Note: NA indicates insufficient feeder sample size for this category.

Table 4.2 Endeavour modelled annualised costs – existing and efficient

Total annualised costs ($ millions)	Urban	Short Rural	Long Rural
Total existing	230.9	194.6	NA
Total efficient	133.3	134.3	NA
Network costs existing	202.0	168.7	NA
Network costs efficient	86.5	103.5	NA
Reliability costs existing	28.9	25.9	NA
Reliability costs efficient	46.8	30.8	NA

Note: NA indicates insufficient feeder sample size for this category.

Table 4.3 and Table 4.4 set out the key outputs of the model for Essential Energy. On average the efficient levels of SAIDI are higher than existing for urban feeders but lower than existing for short-rural and long rural feeders. Similar to Endeavour Energy, our modelling also found that these efficient levels of reliability can be delivered for a lower network cost as indicated by the reduction in total annualised costs.

Table 4.3 Essential modelled SAIDI – existing and efficient (mins per year)

Reliability	Urban	Short Rural	Long Rural
Existing SAIDI	43.3	192.1	647.4
Efficient SAIDI	72.8	180.5	515.5

Note: These results exclude any feeders greater than 500 km.

Table 4.4 Essential modelled annualised costs – existing and efficient

Total annualised costs ($ millions)	Urban	Short Rural	Long Rural
Total existing	60.7	518.8	457.15
Total efficient	35.5	401.6	375.12
Network costs existing	51.4	434.4	392.36
Network costs efficient	20.9	326.3	327.77
Reliability costs existing	9.3	84.4	64.79
Reliability costs efficient	14.6	75.3	47.35

Note: These results exclude any feeders greater than 500 km.

Table 4.5 and Table 4.6 set out the key outputs of the model for Ausgrid. As noted above these estimates include our best estimates of feeder-specific VCRs and will be updated once further information is provided by Ausgrid. These results indicate similar trends to Endeavour Energy– that is an increase in SAIDI from existing to efficient reliability and also lower network costs to achieve the efficient levels of reliability.

Table 4.5 Ausgrid modelled SAIDI – existing and efficient (mins per year)

Reliability	Urban	Short Rural	Long Rural
Existing SAIDI	52.2	154.3	NA
Efficient SAIDI	65.5	162.6	NA

Note: These results exclude any feeders greater than 500 km. NA indicates insufficient feeder sample size for this category.

Table 4.6 Ausgrid modelled annualised costs – existing and efficient

Total annualised costs ($ millions)	Urban	Short Rural	Long Rural
Total existing	250.3	144.7	NA
Total efficient	170.3	111.5	NA
Network existing	193.8	118.5	NA
Network efficient	106.4	84.3	NA
Reliability existing	56.4	26.2	NA
Reliability efficient	63.9	27.2	NA

Note: These results exclude any feeders greater than 500 km. NA indicates insufficient feeder sample size for this category.

We are not recommending that the individual feeder standards be set to the efficient level of reliability indicated by our modelling. As noted in Chapter 2, the distributors already have an incentive to move towards the efficient levels under the AER's revenue incentive schemes (including STPIS).

However, we consider the results of our modelling provide a useful indication of the types of options that should be considered by the distributors when developing their own models of efficient reliability. These models should take into account the specific characteristics of their network and their operating environment that have not been captured in our estimates. While the distributors cannot immediately deliver the efficient levels of reliability indicated by our modelling, they should continue engaging with customers and considering how to move towards efficient levels over time (eg, when considering capital expenditure associated with the replacement of or growth in assets).

4.3.2 Stage 2 – Developing individual feeder standards

The second stage of our approach involved taking the outputs of stage 1 and undertaking further analysis to decide what level to set the standard for each feeder. Our proposed approach involved four main steps:

1. Deciding whether to maintain the feeder types currently in the licence – CBD, urban, short rural and long rural.
2. Deciding whether to set a different standard for each distributor or apply a common approach across all three.
3. Adjusting the outputs of the model to allow for variation in feeder performance.
4. Setting a standard to reflect steps 1 to 3 (including the formula to be used and any caps on the application of the formula).

The sections below set out further information on each of the steps.

Deciding whether to maintain the existing feeder types in the model

The first step in developing feeder standards was to consider whether we should maintain the existing feeder categories for non-CBD feeders, urban, short-rural and long-rural. We looked at the extent to which the current feeder categories capture the variation in factors that affect reliability.

We have found that there is a strong relationship between feeder length and the efficient long-term reliability of individual feeders. In particular, the longer a feeder is, the higher the efficient level of SAIDI (and the lower the level of efficient reliability). While the existing categories capture this variation to some degree, they do so in quite a broad manner, putting all feeders into one of three categories based on maximum demand per km and feeder length:

- Urban - a feeder with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km and which is not a CBD Sydney Feeder.
- Short-rural - a feeder with a total feeder route length less than 200 km, which is not a CBD feeder or urban feeder.
- Long-rural - a feeder with a total feeder length greater than 200 km which is not a CBD Sydney feeder or an urban feeder.

We found that generally, the longer the feeder, the higher the efficient level of SAIDI (and the lower the efficient level of reliability). Therefore, we consider the required level of SAIDI for all non-CBD feeders should be determined based on feeder length only, regardless of feeder category and distributor. Including the maximum demand per km increases the complexity of the formula we propose but does not significantly improve the strength of the statistical relationship.

Although the licences would not specify the required level of SAIDI using the three feeder categories from the national guidelines, the distributors would still be able to report under the licences using these categories to aid in comparison to information reported to the AER.

Deciding whether to set a different standard for each distributor

The current individual feeder standards set out the same or similar minimum levels of SAIDI for each distributor[37]. Although our modelling in stage 1 reflected the costs and values of reliability specific to each distributors' feeder, we consider it appropriate to maintain the current approach and set a common formula across all three distributors.

When we investigated the relationship between efficient SAIDI and feeder length using a formula specific to each distributor, we found that the results were not significantly different across networks. As a result, we considered it appropriate to use one formula common to all three distributors. This approach also ensures that the same minimum level of reliability would apply to feeders with similar characteristics in different parts of the state served by different distributors – for example a 5 km feeder supplying largely residential customers would have the same minimum level of reliability in Newcastle (supplied by Ausgrid) as in Wollongong (supplied by Endeavour).

Adjusting for variation in feeder performance

We consider that the minimum level of performance required by the standard should allow for expected variation from the long-term efficient levels estimated by our feeder models.

As a result, we recommend that the distributors should only be required to investigate and report on feeders where performance is substantially worse than our estimate of long-term efficient levels. We have used an econometric approach to estimate an appropriate degree of fluctuation.

Our estimate of efficient levels of reliability were based on average fault rates and average durations for outages. In practice, we consider the fault rates follow a Poisson distribution[38] and the durations follow a log-normal distribution.

We have set the standard such that the probability of an individual feeder exceeding it is about 1% in any year on average. That implies an expectation that approximately 1% of feeders would be non-compliant with the standard in any year.

Recommended levels of SAIDI

We have developed a single-feeder statistical model that allows us to determine the 1 percentile level of SAIDI relative to the efficient levels at average fault rates and durations. Further detail on this model is set out in Appendix D.

Our recommended formula is set out below.

$$SAIDI\ =\ 330 +\ 55.2\sqrt{length}\ + MIN(160, \frac{5500}{length})$$

37 Essential Energy has slightly higher levels of SAIDI and SAIFI for urban feeders compared to Ausgrid and Endeavour Energy – 400 minutes compared to 350 minutes for SAIDI and 6 interruptions compared to 4 interruptions per customers for SAIFI (see Appendix B).

38 The Poisson distribution is the discrete probability distribution of the number of events occurring in a given time period, given the average number of times the event occurs over that time period. A log normal distribution occurs when the logarithm of a variable is log-normally distributed.

Our single-feeder model calculates the 1% SAIDI levels for every individual feeder in each of the three networks. We then use regression to establish a best-fit threshold that can be embodied in the single-feeder standard.

4.4 How did we set required levels of SAIFI for urban, short rural and long rural feeders?

We also consider that the levels of SAIFI specified in the standard should be informed by the long-term efficient levels of reliability. However, the AER's VCR estimates are expressed in units of $/kWh and are better suited to estimating the impact on the efficient duration of interruptions measured via SAIDI rather than the frequency of interruptions measured via SAIFI. We consider that more work should be done on measuring the value of avoiding frequent interruptions to customers before setting a standard on this basis.

In the interim, we recommend that the distributors should be required to investigate individual feeders where the SAIFI substantially differs from existing levels of performance.

As with SAIDI, we have found that there is a strong relationship between feeder length and the existing SAIFI of individual feeders. Therefore, we consider the required level of SAIFI for all non-CBD feeders should also be determined based on feeder length only, regardless of feeder category and distributor.

We have also developed a single-feeder statistical model that allows us to determine the 1 percentile level of SAIFI relative to the actual levels at average fault rates and durations. Further detail on this model is set out in Appendix D.

Our recommended formula is set out below.

$$SAIFI = 3 + 0.23\sqrt{length} + MIN(0.65, \frac{21}{length})$$

Our single-feeder model calculates the 1% SAIFI levels for every individual feeder in each of the three networks. We then used a regression to establish a best-fit threshold that can be embodied in the single-feeder standard.

4.5 How do our recommended levels of SAIDI and SAIFI for non-CBD feeders compare to the current standards?

Table 4.7 sets out the individual feeder SAIDI and SAIFI resulting from applying our draft recommendations for a range of feeders.

Table 4.7 Individual feeder standards for typical feeders

Feeder type	Length	Current SAIDI	Draft SAIDI	Current SAIFI	Draft SAIFI
Typical urban feeder[a]	5	350/400[a]	613	4/6[b]	4.2
Typical exurban short rural feeder	15	1000	704	8	4.5
Typical country short rural feeder	40	1000	817	8	5.0
Typical long rural feeder	250	1400	1,225	10	6.7

a Ausgrid and Endeavour Energy have an existing SAIDI standard for urban feeders of 350 minutes and Essential Energy has an existing SAIDI standard for urban feeders of 400 minutes.

b Ausgrid and Endeavour Energy have an existing SAIFI standard for urban feeders of 4 outages and Essential Energy has an existing SAIFI standard for urban feeders of 6 outages.

Compared to the current standards, our draft recommendations result in the following for different feeder types:

- Urban: a higher level of SAIDI and similar levels of SAIFI for most feeders
- Short rural: a lower level of SAIDI and SAIFI for most feeders
- Long rural: Slightly lower levels of SAIDI and lower levels of SAIFI for most feeders.

The tables below estimate the average number of feeders we expect to exceed the SAIDI and SAIFI levels based on data from 2014-15 to 2018-19 reported by the distributors to the AER. We expect this to be a similar number of feeders compared to the existing standards for Ausgrid and Endeavour and an increase for Essential. However we expect fewer urban feeders and more short rural feeders to require investigation than under the current standards.

Table 4.8 Non-complying feeders under existing and recommended standards

Feeder type	Existing standards		Recommended standards		Total feeders
	5-year average	% of feeders	5-year average	% of feeders	
Ausgrid[a]	**51.8**	***3.0%***	**32.4**	**1.9%**	**1,731**
Urban	42.8	*3.1%*	19.4	1.4%	1,366
Short rural	7.2	*2.3%*	11.4	3.6%	316
Long rural	0.2	*4.0%*	0.2	4.0%	5
Endeavour Energy	**25.6**	***1.7%***	**24.6**	**1.6%**	**1,535**
Urban	20.0	*1.9%*	9.2	0.9%	1,074
Short rural	5.2	*1.1%*	15.0	3.3%	460
Long rural	0.4	*40.0%*	0.4	40.0%	1
Essential Energy	**64.8**	***4.4%***	**105.4**	**7.2%**	**1,461**
Urban	7.6	*2.6%*	6.2	2.1%	294

Feeder type	Existing standards		Recommended standards		Total feeders
	5-year average	% of feeders	5-year average	% of feeders	
Short rural	40.2	*4.4%*	75.4	8.2%	924
Long rural	17.0	*7.0%*	23.8	9.8%	243

a The total figures for Ausgrid include the 44 CBD feeders. The total figures use the existing CBD feeder standards.

Table 4.9 Non-complying SAIDI feeders under existing and recommended standards

Feeder type	Existing standards		Recommended standards		Total feeders
	5-year average	% of feeders	5-year average	% of feeders	
Ausgrid[a]	**37.8**	***2.2%***	**13.6**	**0.8%**	**1,731**
Urban	31.8	*2.3%*	5.4	0.4%	1,366
Short rural	4.4	*1.4%*	6.6	2.1%	316
Long rural	0.2	*4.0%*	0.2	4.0%	5
Endeavour Energy	**20.8**	***1.4%***	**11.2**	**0.7%**	**1,535**
Urban	15.6	*1.5%*	3.2	0.3%	1,074
Short rural	4.8	*1.0%*	7.6	1.7%	460
Long rural	0.4	*40.0%*	0.4	40.0%	1
Essential Energy	**61.0**	***4.2%***	**71.8**	**4.9%**	**1,461**
Urban	7.2	*2.4%*	2.4	0.8%	294
Short rural	37.2	*4.0%*	51.4	5.6%	924
Long rural	16.6	*6.8%*	18.0	7.4%	243

a The total figures for Ausgrid include the 44 CBD feeders. The total figures use the existing CBD feeder standards.

Table 4.10 Non-complying SAIFI feeders under existing and recommended standards

Feeder type	Existing standards		Recommended standards		Total feeders
	5-year average	% of feeders	5-year average	% of feeders	
Ausgrid[a]	**19.4**	***1.1%***	**21.8**	**1.3%**	**1,731**
Urban	15.8	*1.2%*	15.0	1.1%	1,366
Short rural	3.4	*1.1%*	6.8	2.2%	316
Long rural	0.0	*0.0%*	0.0	0.0%	5
Endeavour Energy	**10.2**	***0.7%***	**19.4**	**1.3%**	**1,535**
Urban	8.8	*0.8%*	7.0	0.7%	1,074
Short rural	1.0	*0.2%*	12.0	2.6%	460
Long rural	0.4	*40.0%*	0.4	40.0%	1
Essential Energy	**12.0**	***0.8%***	**64.6**	**4.4%**	**1,461**
Urban	1.4	*0.5%*	4.8	1.6%	294
Short rural	6.8	*0.7%*	46.4	5.0%	924
Long rural	3.8	*1.6%*	13.4	5.5%	243

a The total figures for Ausgrid include the 44 CBD feeders. The total figures use the existing CBD feeder standards.

Note: These estimates are based on information reported by distributors to the AER in the Regulatory Information Notices (RIN). There may be differences between estimates based on RIN data compared to data measured against the licences due to differences in how some excluded events are currently treated (eg, there is a different major event day definition for Endeavour Energy).

Our proposed feeder standards vary by length. By contrast, the existing feeder standards vary by length (ie, short rural feeders are shorter than 200km and long rural feeders are longer than 200km) and maximum demand per km (ie, urban feeders have greater than 0.3 MVA/km and rural feeders have less than 0.3 MVA/km). Our proposed approach means that there is not a significant increase in feeder standards at 0.3MVA/km as is the case with current standards. However, it does mean that some feeders with similar length but very different maximum demand and potential impacts on unserved energy would have the same standard. We are seeking feedback from stakeholders on the functional form of our feeder standards.

We have also published a list of the minimum SAIDI and SAIFI standards to apply to each feeder for each distributor on our website.

4.6 How should minimum levels of SAIDI and SAIFI be set for CBD feeders?

As noted above, we have developed models for each of the distributors' non-CBD feeders. Ausgrid is the only distributor that has CBD feeders. The nature of Ausgrid's CBD network and the degree to which it relies on the transmission network to deliver the required level of reliability means that there is additional complexity associated with modelling this part of Augrid's network. In other words, the picture is complicated by the fact that Ausgrid's CBD feeders form part of the N-2 redundancy arrangements that Transgrid relies on. In a sense, these feeders serve not only Ausgrid's customers, but also Transgrid.[39]

We are asking Ausgrid to develop its own modelling of long term efficient reliability for these feeders and propose the minimum levels of SAIDI and SAIFI that should apply. We will assess their proposal and set out draft recommendations in a supplementary report to be released in March 2020.

4.7 How should we set direct connection standards?

The current individual customer standards set minimum levels of SAIDI and SAIFI for around 400 large industrial customers that are directly connected to the distributors' network by sub-transmission feeders. These individual customer standards were introduced in 2018 and are currently split into two categories:

- Metropolitan with SAIDI and SAIFI set equal to the individual feeder urban levels
- Non-metropolitan with SAIDI and SAIFI set equal to individual feeder short-rural levels.

39 The N, N-1, N-2 notation is used to refer to security or redundancy levels previously used in deterministic reliability standards. Standards were expressed using 'N-x' notation, where N refers to the number of elements in a part of the network and x is the number of elements that can fail at the same time without causing an interruption to power supply. For example, a network built to a strict N-1 standard will be able to supply peak load with one element not operating, even if it is the largest element in the network.

We are recommending that the standards be renamed direct connection standards to better reflect the type of customers that they cover. In addition, we consider that the minimum levels of SAIDI and SAIFI should be updated to reflect our modelling of long-term efficient levels of SAIDI and actual levels of SAIFI.

Since we are no longer recommending different standards for urban and short-rural feeders, there is no equivalent feeder type to align metropolitan and non-metropolitan feeders. Rather, we are recommending one direct connection standard for all areas, using the same formula for SAIDI and SAIFI for individual feeders but using a 'proxy' feeder length of 1 km. This results in a SAIDI and SAIFI direct connection standard for all areas that is similar to the existing non-metropolitan standard.

Direct connection customers may also be on arrangements where they have negotiated a lower level of reliability. The current licence allows the distributors to consider this when investigating direct connections that do not meet the standards. We consider that this should be retained as it allows for the situation where a customer is receiving a lower level of reliability consistent with the redundancy arrangement that they originally agreed to and paid for.

While we do not expect our draft recommendations to have a substantial impact on the level of reliability provided to direct connection customers, we are interested in any feedback from customers that consider this may be the case.

4.8 Should the investigating and reporting approach in the existing licences be retained?

We found the requirements related to monitoring, investigating and reporting on the reliability of individual feeders that do not meet the standard are appropriate and should be retained. Importantly, these requirements mean the standards do not encourage the distributors to invest in improving feeder reliability where the benefits to customers do not exceed the costs.

Box 4.2 sets out the proposed approach that would be required by the licence when an individual feeder does not meet the standard. We have retained the policy intent of the existing licence requirements but are recommending some minor changes to the current drafting in the licence to more clearly set out what is required by the distributors at each stage.

Box 4.2 Reporting and investigation for individual feeder standards

5A.1 (a) Where the *Licence Holder* has exceeded any of the *individual feeder standards* or *direct connection standards* in a *quarter*, the *Licence Holder* must prepare:

(i) an *investigation report* by the end of the *quarter* immediately following the *quarter* the relevant standard was exceeded; and

(ii) a *rectification plan* within 3 months of the completion of the *investigation report*.

(b) Where the cause or causes for exceeding the standard have already been rectified before an *investigation report* is required to be prepared under condition 5A.1(a) above, the *Licence Holder* is not required to prepare a *rectification plan* in respect of that breach of the relevant standard.

5A.2 An *investigation report* must:

(a) identify the cause or causes for exceeding the relevant *individual feeder standard(s)* or *direct connection standard(s)*;

(b) where the cause or causes identified in paragraph (a) have already been rectified, identify the steps taken to rectify the causes, including when the steps were completed;

(c) where the cause or causes identified in paragraph (a) have not yet been rectified or fully rectified, identify any reasonable solutions that can be implemented to rectify the causes to improve conformance with the relevant *individual feeder standards* or *direct connection standards,* including:

(i) whether the solutions:

(A) involve expenditure on a distribution asset (network options); or

(B) do not involve expenditure on a distribution asset (non-network options); and

(ii) the steps required to implement each solution; and

(d) in the case of an *investigation report* prepared because the *Licence Holder* has exceeded a *direct connection standard* - consider the terms of the *connection contract* (including network security arrangements) agreed with the *customer* of the affected *connection point*, including when the *customer* was connected to the *Licence Holder's distribution system*.

5A.3 A *rectification plan* must:

(a) set out:
(i) the solution(s) selected (unless clause 5A.3(b)(ii) applies such that there is no solution selected) to rectify the cause or causes for exceeding the relevant *individual feeder standard(s)* or *direct connection standard(s);* and
(ii) the timeframes for completing the steps required to implement the solution(s);

(b) apply the following principles:
(i) the solution(s) selected must be subject to a cost-benefit analysis and must demonstrate a positive net benefit;
(ii) the Licence Holder may decide not to select a solution only if there is no solution that demonstrates a positive net benefit following cost-benefit analysis;
(iii) all reasonable steps to improve conformance with the individual feeder standards or direct connection standards should be taken;
(iv) the timeframe for rectification should be as short as reasonably practicable;
(v) implementation of the rectification plan must commence no later than 6 months from the date the investigation report is completed; and
(vi) solutions identified in condition 5A.2(c) involving a non-network option are preferred where they are equal or more cost-effective than a network option.

5A.4 If the Licence Holder has prepared a *rectification plan* which identifies a selected solution in accordance with clause 5A.3, the Licence Holder must implement that *rectification plan*.

5A.5 If, following a cost-benefit analysis in accordance with condition 5A.3, the *Licence Holder* determines not to select a solution, the *Licence Holder* must, within one month of that determination, advise the *Tribunal* of the *Licence Holder's* ongoing non-conformance with the relevant *individual feeder standards* or *direct connection standards*.

5 Guaranteed customer service level and payments

The current customer service standards require distributors to pay $80 to customers that:

1. Experience very long or multiple outages over a year, and
2. Apply for a payment.

We have considered the role of these standards and how to set these levels, having regard to schemes applying in other jurisdictions and our own analysis of the role and objectives of these payments. The sections below provide an overview of our draft findings and recommendations on changes to these standards and then discuss them in more detail.

5.1 Overview of draft recommendations

We recommend renaming the customer service standard the 'guaranteed service level'. The guaranteed service level sets the minimum acceptable service level of the distributor's electricity supply.

The guaranteed service level and associated payments should apply to residential and small business customers most of whom are supplied under the deemed standard connection contract. We do not consider they should apply to large customers that enter into negotiated contracts with a distributor. These businesses should be well placed to negotiate their minimum service levels. We are seeking comment on whether the guaranteed service level should apply to residential and small business customers on negotiated contracts.

We are recommending a two tiered guaranteed service level:[40]

1. A Level 1 guaranteed service level that reflects the historical 1% of worst service provided by NSW distributors:
   - Not more than 8 outages or 15 hours of cumulative outage per financial year for Ausgrid and Endeavour Energy
   - Not more than 10 outages or 20 hours of cumulative outage per financial year for Essential Energy.
2. A Level 2 guaranteed service level that reflects the historical 0.1% of the worst service provided by NSW distributors:
   - Not more than 20 outages or 40 hours of cumulative outage per financial year for Ausgrid and Endeavour Energy
   - Not more than 30 outages or 60 hours of cumulative outage per financial year for Essential Energy.

The same set of exclusions would apply to the guaranteed service level payments as the individual feeders (described in Chapter 3).

40 The existing guaranteed service level is a single outage of 12 hours or four outages of 4 hours in metropolitan areas and a single outage of 18 hours four outages of 5 hours elsewhere.

Consistent with the existing licence conditions, we recommend that non-compliance should entitle customers a payment on application.[41] Although many stakeholders supported automatic payments, we consider that a payment made on application is more consistent with the principle of a refund for poor performance. An automatic payment would also be more difficult and costly for the distributors to administer, and in some cases payments would be made to customers who were not sufficiently impacted by the outages (eg, when the customers were not home).

We recommend basing the payment on a refund of distribution charges. This approach reflects that refunds are a common remedy for not meeting contractual conditions. It would also link the payments to distributor costs, which change over time. To reduce administrative complexity, we recommend setting the payments equal to:

- The annual fixed charge component of distribution[42] charges for the anytime residential and business tariffs for not complying with the Level 1 guaranteed service level, and
- The annual variable charge component of distribution charges for a typical customer on an anytime residential and business tariffs for not complying with the Level 2 guaranteed service level.[43]

Finally, we recommend distributors take reasonable steps to make eligible customers aware of the availability of guaranteed service level payments and to report annually on:

- How many customers are eligible for, applied for and received the guaranteed service level payments, and
- How much distributors paid in other compensation schemes and what distributors cover in their other compensation schemes.

5.2 What is the guaranteed service level?

The guaranteed service level specifies a minimum service level for individual customers and complements the individual feeder standards.

The individual feeder standards require a service level is met on average across a feeder which could serve anywhere from one to 5,000 customers.[44] A distributor can meet the individual feeder standard overall, while some customers on the feeder receive a very unreliable supply. The guaranteed service level protects individual customers from receiving this unreliable supply.

41 The existing guaranteed service level entitles customers to an $80 payment for each breach up to $240 per year.

42 Distribution charges means distribution use of system (DUOS) charges.

43 Under our recommendation, where the distributor does not meet its guaranteed service level, a customer is eligible for one Level 1 guaranteed service level payment and one Level 2 guaranteed service level payment each financial year.

44 We discuss the individual feeder standards in Chapter 3 and Chapter 4.

The purpose of the guaranteed service level is to protect customers by setting *minimum acceptable service levels*. Previously, its role was to provide incentives for utilities to improve service quality in their worst performing areas.[45] Now, the AER's STPIS provides those incentives for distributors to make economic investments in reliability.

5.2.1 Guaranteed service level should apply to residential and small business customers

The guaranteed service level and associated payments should apply to residential and small business customers most of whom are supplied under the deemed standard connection contract. Some residential and small business customers may be supplied via a negotiated connection agreement as their supply arrangements are not standard. We are seeking stakeholders' views on whether residential and small business customer on negotiated contracts should be covered by the guaranteed service level and associated payments.

An example of a non-standard supply arrangement is when a distributor may offer a 'behind the meter battery' to provide a more reliable supply. Distributors may not offer such a service if they cannot negotiate a supply contract with lower technical reliability and remove the associated guaranteed service level payments. In this case, customers would not be best served by not allowing distributors to negotiate away the guaranteed service level and associated payments.

However if distributors require many residential and small business to negotiate connection contracts for reasons outside the customers' control then is would be appropriate for the guaranteed service level to apply to distributors negotiated connection contracts with small customers.

It is not necessary for the guaranteed service level to apply to large customers that enter into negotiated connection contracts with a distributor. These businesses would be well placed to negotiate their minimum service levels.

Draft Recommendation

15 The guaranteed service level should set the minimum acceptable level of reliability and apply to residential and small business customers supplied under the deemed standard connection contract.

IPART seeks comments on the following

1 Should the guaranteed service level apply to residential and small business that are supplied on negotiated connection agreements?

45 When IPART reviewed the customer service standards in 2003-04, the Tribunal recommended the purpose of the customer service standard is to provide incentives for utilities to improve service quality in their worst performing areas. IPART, *Review of GCSS and operating statistics – Final recommendations,* Report to the Minister, April 2004, p 8.

5.2.2 Guaranteed service level should exclude the same outages as feeder standards

Like the individual feeder standards, we consider it appropriate that the guaranteed service level exclude events over which distributors have no or little control. Specifically, we recommend the guaranteed service level should use the same exclusions as the individual feeder standards.[46]

Currently, customer service standards have different exclusions to the existing individual feeder standards. We consider having different exclusions adds unnecessary complexity to reporting and has no observable benefit to customers. In particular, the major event day exclusion may be difficult for customers to understand. However the existing exclusion for severe weather is difficult to define and administer.

Draft Recommendation

16 The guaranteed service level should only apply to interruptions that contribute to individual feeder standard performance. That is the same exclusions should apply to both the guaranteed service level and individual feeder standards.

5.3 How should we set the guaranteed service level?

The guaranteed service level should protect customers from poor service. By poor service we considered the worst performances based on 2 different levels of outages:

- 1% of worst service for Level 1 guaranteed service level, and
- 0.1% of worst service for Level 2 guaranteed service level.

We consider that SAIDI and SAIFI style measures better protect customers from multiple long outages and very long outages than the current customer service standards. They will also protect customers from more frequent shorter outages.

This approach is similar to the Victorian Essential Services Commission's approach to setting its guaranteed service level.

To set the hours for the cumulative outage guaranteed service level, we calculated the outage levels, based on analysis of the distributors Regulatory Information Notices to the AER since 1 July 2014 (see Table 5.1).[47]

Table 5.1 Hours of outages for worst served customers (July 2014 – June 2019)

Worst served customers	Ausgrid	Endeavour Energy	Essential Energy	NSW
5%	4	3	7	5
2%	9	5	12	9
1%	21	7	16	15
0.5%	32	9	20	24

46 We discuss the exclusions to the individual feeder standards in Chapter 3.

47 However, we cannot identify when customers experience multiple outages from this data, so we have used individual outages as a proxy for the duration of outages.

Worst served customers	Ausgrid	Endeavour Energy	Essential Energy	NSW
0.1%	34	17	34	34
0.01%	56	31	71	57

Note: Data excludes planned outages, and major event days.

Note: We do not have useful data for the outage frequency standard. We calculated it as a multiple of the cumulative duration data (assuming that every 2 hours of duration is equal to one outage). This approach reflects the Victorian Distribution Code and the AER's decision to rebalance STPIS towards SAIDI.

For the guaranteed service level, we grouped Ausgrid and Endeavour Energy because they serve primarily urban networks. As is currently the case we recommended a slightly lower guaranteed service level for Essential Energy to reflect the lower density of its network.

5.4 How should the licence treat distributors who do not meet the guaranteed service level?

We recommend that when distributors do not meet the guaranteed service level, they must make payments available to affected customers upon request. The distributor must take reasonable steps to ensure that eligible customers are made aware that they are eligible for payments. Our recommendations are consistent with the current customer service standard (and associated payments).

5.4.1 Payments to customers are an appropriate penalty for not meeting the guaranteed service level

We consider it appropriate that distributors that do not meet the guaranteed service level provide payments to affected customers. This approach directly acknowledges the distributor did not meet its obligations to the customer.

Our recommendation is consistent with the approach in the current licence. Existing licences address not meeting a standard in a range of ways. In particular, the current licence:

- Treats distributors as non-compliant for exceeding overall feeder standards,
- Requires distributors to investigate and, where economic, improve reliability when exceeding individual feeder and customer standards, and
- Makes distributors provide $80 to customers, on application, for exceeding customer service standards.

We consider that finding a distributor non-compliant for exceeding the guaranteed service level is not commensurate with the harm of exceeding the guaranteed service level. Similarly, we consider that requiring distributors to investigate and improve reliability each time it exceeds the guaranteed service level would create an unreasonable burden on the distributors. Payments provide an acknowledgement and a form of compensation for exceeding the standard, directly to those affected.

We recommend payments remain on application. Consultation revealed customer advocates supported automatic payments, but distributors did not.

We consider more customers should receive guaranteed service level payments. In 2018-19, Endeavour Energy and Essential Energy made very few payments, for example.[48] Making payments automatic is one way to achieve our goal of more customers receiving payments.

However:

- Distributors often cannot identify which customers experience an outage.
- Distributors do not usually have direct billing relationships with customers to send payments directly, and
- Customers may not experience each outage.

Therefore, we recommend distributors take reasonable steps to ensure customers are aware of payments (with no licence minimum of what steps distributors must take). However we expect the distributors to use more effective targeted actions. We are recommending removing the existing minimum criteria set out in the licence[49] and allowing IPART to assess whether distributors are taking all reasonable and effective steps to inform customers of their eligibility for guaranteed service level payments. Reasonable steps do not require distributors to incur additional expenditure, but to take more effective targeted action at informing eligible customers.

Draft recommendations

17 When a distributor does not meet its guaranteed service level, it must make payments available, on request, to affected customers.

18 Distributors must take reasonable steps to ensure eligible customers are aware they are eligible for payments. Distributors no longer need to publish details of the guaranteed service level and associated payments in a newspaper, however they need to:

   – Publish the dollar value of the guaranteed service level payments on their website each year.

   – Provide information on the guaranteed service level payments in any information or communication to customers regarding a specific interruption.

   – Follow any directions from IPART on additional steps distributors must take to notify customers.

5.5 What payments should customers receive?

The guaranteed service level payments should act as a proxy for a refund when this level is not met. Our draft recommendations reflect that a refund is a common remedy for not meeting service obligations and also ensures that payments are linked to distributor costs which change over time.

48 Endeavour Energy made 3 customer service standard payments and Essential Energy made 26 customer service standard payments in 2018-19. 2018-19 Q4 reliability reports for Ausgrid, Endeavour Energy and Essential Energy.

49 Distributors are currently required to publish the customer service standard and associated payments on their website and once a year in a newspaper.

We are recommending two levels of payments, summarised in Table 5.2. Based on the distributors' current reliability performance, around 1% of customers could receive the first payment, which would be roughly equal to the distribution network **service** charge included in their annual electricity bills. Around 0.1% of customers could receive the second payment, which would be roughly equal to the distribution network **usage** charge included in their annual electricity bills.

Table 5.2 Recommended guaranteed service levels and payments ($2020-21)

Customer service standard	Ausgrid	Endeavour Energy	Essential Energy	Payment
Level 1	15 hours, or 8 outages	15 hours, or 8 outages	20 hours, or 10 outages	Equal to the distribution network service charge in each network. For residential customers this would be around $152-$336 depending on network area.
Level 2	40 hours, or 20 outages	40 hours, or 20 outages	60 hours, or 30 outages	Equal to the distribution network usage charge in each network For residential customers this would be around $205-$410 depending on network area.

Our draft recommendations differ from the current $80 payments for exceeding the customer service standard. We propose designing the payment to reflect a refund.

Setting the guaranteed service level payments in this way solves two major issues:

1. It creates a basis and a justification for the amount of the payment. We note that refunds are a common way businesses acknowledge they did not meet the customers' expectations or agreed service levels.
2. It ensures that guaranteed service level payments will not decline in value relative to distribution costs. Setting the payments equal to the regulated tariffs ensures the payment does not decline in value over time. For example, we first recommended the existing $80 payment in 2003, $80 in 2003 is worth:
   - $113.55 in 2020 relative to the change in general inflation
   - Around $200 in 2020 relative to the change in regulated retail electricity tariffs.

However, it is important that the guaranteed service level payments are easy to explain and easy for distributors to administer. Therefore, we recommend standardising the payments to equal specific tariffs at specific customer usage. This reduces the administrative complexity and allows distributors to publish a refund amount each year that applies to residential customers and business customers. Our recommended guaranteed service level payment tariffs and usage are outlined in Table 5.3.

Table 5.3 Recommended guaranteed service level payment parameters

	Ausgrid	Endeavour Energy	Essential Energy
Residential tariff	EA010	N70	BLNN2AU
Residential usage[a]	3,900 kWh	4,900 kWh	4,600 kWh
Business tariff	EA050	N90	BLNN1AU

	Ausgrid	Endeavour Energy	Essential Energy
Business usage[b]	9,200 kWh	10,000 kWh	6,200 kWh

a The residential usage is set equal to the 2019-20 Default Market Offer usage benchmarks

b The business usage is set equal to the median usage for small business customers distributors provided IPART.

Note: We have included in our licence drafting a process to update the payments after a tariff structure statement if any of the tariffs listed above are discontinued.

We are proposing that the licence will require distributors to publish the annual payments on their website. Table 5.4 shows what the guaranteed service level payments would be under the 2020-21 annual price determinations.

Table 5.4 Proposed payments based on 2020-21 distribution tariffs (DUOS incl GST)

	Ausgrid	Endeavour Energy	Essential Energy
Residential level 1	152	156	336
Residential level 2	205	375	410
Business level 1	507	223	336
Business level 2	469	712	796

a The residential usage is set equal to the 2019-20 Default Market Offer usage benchmarks

b The business usage is set equal to the median usage for small business customers distributors provided IPART.

Note: We have included in our licence drafting a process to update the payments after a tariff structure statement if any of the tariffs listed above are discontinued.

Our recommended payments are within or near important benchmarks, including the value of customer reliability, historical value of current payment and comparable guaranteed service level schemes. Our proposed payment levels balance simplicity (by being annual refunds) while maintaining comparability with these benchmarks (see Table 5.5).

Draft Recommendation

19 When distributors breach the Level 1 guaranteed service level affected customers should be eligible for a payment equal to the annual distribution service charge for a typical customer.

20 When distributors breach the Level 2 guaranteed service level affected customers should be eligible for a payment equal to the annual distribution usage charges for a typical customer.

Table 5.5 Comparison of proposed payments with relevant comparators

Comparator	$2020-21 Incl GST	1 hour equivalent
Proposed residential payment		
Ausgrid residential:		
– Level 1	152.32	10.15
– Combined Level 1 and Level 2 payment[a]	356.98	8.92
Endeavour Energy residential:		
– Level 1	155.58	10.37
– Combined Level 1 and Level 2 payment[a]	530.26	13.26
Essential Energy residential:		
– Level 1	335.81	16.79
– Combined Level 1 and Level 2 payment[a]	745.58[a]	12.43
Residential comparators		
Current payment of $80:[b]	80	4.44-6.67[d]
– In 2003 adjusted by CPI	117.94	6.55-9.83[d]
– In 2003 adjusted by Ausgrid regulated retail tariff	228.74	12.71-19.06[d]
– In 2003 adjusted by Endeavour Energy retail tariff	192.98	10.72-16.08[d]
– In 2006 adjusted by Essential Energy retail tariff[c]	167.60	9.31-13.97[d]
Victoria's proposed guaranteed service level payments:		
– 12 hours	130	10.83
– 24 hours	190	7.92
– 48 hours	380	7.92
AER's value of customer reliability:[e]		
– Eastern Sydney, Central Coast and Newcastle VCR	29.17/kWh	12.99
- Western Sydney VCR	21.18/kWh	11.84
- Range of Essential Energy VCRs	16.90-26.38/kWh	8.87-13.85

a To compare the level 2 payments we have calculated the total a residential customer can receive over the year where Level 2 guaranteed service level is not met. This is consistent with how we present the Victorian payments.

b The $80 payment was recommended in 2003. The current licence maintains the payment at $80. We have compared the value of $80 now, with $80 in 2003.

c The first regulated retail tariff for Country Energy listed on the IPART website is from 2006.

d The range is due to the difference in metropolitan (12 hours) and non-metropolitan (18 hours) single outage duration.

e Based on annual consumption of 3,900kWh for Eastern Sydney, Central Coast and Newcastle, 4,900kWh for Western Sydney, and 4,600kWh for Essential Energy.

5.6 What should distributors publish?

We recommend that distributors publish information so IPART and the public can monitor how frequently distributors exceed the guaranteed service level, and how many customers are receiving guaranteed service level payments.

5.6.1 Distributors should publish data on how often they exceeded the guaranteed service level

IPART needs to understand the proportion of eligible customers receiving guaranteed service level payments to assess their effectiveness. Under the current licence distributors report only on how many customers apply for customer service standard payments and how many customers receive customer service standard payments. This information is useful, but does not provide any information about how many customers could have received payments.

We recommend adding a requirement for distributors to publish its best estimate of the number of customers for whom it did not meet its guaranteed service level. This information will help IPART assess whether distributors are taking reasonable and effective steps to inform customers that they are eligible for guaranteed service level payments.

Draft recommendation

21 Distributors must publish on their website each year:

- How many customers received payments because the distributor did not meet the guaranteed service level
- How many customers applied for payments because they considered the distributor did not meet the guaranteed service level
- How many customers the distributor estimates received worse service than the guaranteed service level.

5.7 What is the role of compensation schemes?

Ausgrid, Endeavour Energy and Essential Energy each operate voluntary compensation schemes. We consider that voluntary compensation schemes complement the guaranteed service level payments. We recommend that more information on these schemes is shared with the public.

5.7.1 Compensation schemes are for out-of-pocket expenses

The compensation schemes and guaranteed service level serve different purposes. Distributors' compensation schemes reimburse customers for out-of-pocket expenses (up to $5,000) where a distributor's fault caused the expense. To receive compensation, customers must provide evidence of the expense.

By contrast the distributors' guaranteed service level (and associated payments) set the minimum service. The guaranteed service level payments acknowledge distributors did not meet the minimum service level and reduce the cost of the service to customers with poor service. Customers do not need to provide evidence that they incurred a financial cost to receive a guaranteed service level payment.

5.7.2 Effective compensation schemes complement the guaranteed service level

Effective compensation schemes work with the guaranteed service level. They can both provide payments to customers for outages. The compensation schemes complement the guaranteed service level.

We recommend distributors publish their compensation policies and how many payments they make each year. We recognise that where there are effective compensation schemes, some customers may decide they do not need additional payments (in the form of guaranteed service level payments). Therefore, it will be useful to understand how effective compensation schemes are, in assessing whether distributors are taking reasonable and effective steps to inform customers that they are eligible for guaranteed service level payments.

Draft recommendation

22 Distributors should publish on their website:

- Their compensation scheme's policies on eligibility for compensation payments
- How many compensation payments they have made and the total amount paid.

6 Distributed energy resources (DER)

DER refers to the broad range of technologies that operate behind a customer's meter and are capable of offsetting or shifting their demand from the grid, and in some cases exporting energy back to the grid. For example, it includes:

- Generation technologies, such as rooftop solar, wind turbines, biofuels and diesel generators,
- Demand response technologies that shift or curtail the use of certain household appliances such as pool pumps, hot water systems and air conditioners, and
- Storage technologies, including batteries, thermal storage and electric vehicle (EV) charging.

These technologies can be a resilience mechanism, helping to maintain supply to customers where there are supply issues originating from the network. They can also lower customers' bills, and improve reliability outcomes for the worst-served customers. Rooftop solar, for example, can be an alternative for the worst-served customers on the fringe of the network and who may be experiencing lengthy and frequent outages.

However, because the distribution networks were not originally designed for two-way flows of electricity, DER customer exports can create technical challenges for the distributors. Without appropriate management, these exports can cause imbalances in voltage levels, which can damage household appliances and or strain the physical electricity infrastructure. While the extent of the challenges is currently modest in NSW compared to other states, we expect this to increase as the take up of DER continues to grow.

As part of our review, we considered how changes to the reliability standards could encourage the distributors to evolve to enable customers to fully benefit from DER, and recognise the value that DER customers place on the ability to reliably export their excess generation to the grid. In particular, we considered:

- Whether the current regulatory framework creates incentives for the distributors to efficiently accommodate two-way energy flows and manage customer exports,
- If not, how the reliability standards in their licences could be used to create those incentives, and
- How any such reliability standards would interact with national reliability incentives.

To assist us in considering these issues we engaged HoustonKemp to provide advice on an appropriate regulatory framework and associated measures to encourage the distributors to efficiently accommodate two-way energy flows and manage customer exports. HoustonKemp's report is available on our website. We also had regard to stakeholder submissions to our Issues Paper and processes underway at the national level relating to efficiently integrating DER into the energy market (see Box 6.2).

6.1 Overview of draft recommendations and rationale

We are recommending a new DER reporting requirement that would require the distributors to disclose information relevant to the quality of service provided to DER customers. This draft recommendation reflects our finding that the current regulatory framework does not create an incentive for distributors to efficiently invest in DER hosting capacity to allow greater DER exports, and this is having negative impacts on customers.

We recognise that reform processes aimed at efficiently integrating DER into the energy market are currently underway at the national level, and three rule changes related to DER are being considered by the AEMC.[50] However, these national processes are not yet complete, and their completion timeframes are not yet certain.[51]

In the interim, our recommended reporting requirement would provide more data about the impact of export constraints on customers. This could then inform future decisions on whether any supplementary regulatory changes are required at either the national or state level. We will continue to monitor progress at the national level.

Some respondents to our Issues Paper did not consider that network reliability standards should take account of two-way energy flows because electricity export is not an essential service.[52] For example, Business NSW considered regulating energy export services is not as essential as supply services to customers.[53] PIAC noted that the current regulatory framework does not allow the distributors to recover the costs of managing customer exports to the grid therefore the standards should not extend to electricity export.[54] However, given the increase in uptake of DER, we consider these changes are necessary to assist the distributors to evolve to take advantage of new technologies and to ensure the standards reflect the future of the energy system.

Draft recommendation

23 That the distributors' licences include a DER information disclosure requirement commencing in 2021-22.

50 AEMC Consultation Paper, Distributed Energy Resources Integration – Updating Regulatory Arrangements, 30 July 2020.

51 As above, p 5. The next milestone is for the AEMC to publish a draft determination and the current date for this is 19 November 2020.

52 Section 4(1)(a) of the *Essential Services Act* 1988 (NSW) defines essential services as the production, supply or distribution of any form of energy, power or fuel or of energy, power or fuel resources

53 Business NSW, Submission to the Issue Paper, p 4.

54 PIAC, Submission to Issues Paper, May 2020, p 5.

6.2 Does the regulatory framework create incentives for distributors to efficiently accommodate two-way energy flows?

HoustonKemp found that the current regulatory framework is weighted towards minimising expenditure, without any counterbalancing incentives for the distributors to provide DER hosting capacity to allow greater DER exports.[55] The concept of minimising expenditure does not include making the most efficient investment decisions to resolve the network issues caused by DER.

Based on its consultation with the distributors, HoustonKemp found that the distributors currently:

- Have limited awareness of DER connections. This awareness is limited to connection applications, and this has recently been enhanced by the introduction of AEMO's DER register (discussed in section 6.4 below).[56]
- Have limited visibility of DER constraints on their network. They rely on complaints from customers. These include DER customers who are unhappy about any imposed limits on how much electricity they can export onto the grid, as well as non-DER customers who experience voltage and thermal capacity issues.[57]

These limitations mean the distributors are currently unable to estimate the amount of DER export to their network when planning or managing the voltage levels for supply of electricity to customers. They also mean customers considering investing in DER cannot easily identify the extent of network export constraints in their area before making their decision.

Essential Energy's area has the highest uptake of DER and it is experiencing the most DER constraints issues in NSW.[58] It has started actively curtailing DER exports to ensure its network operates as required, as well as using inverters to reduce and stop output when necessary.[59] Ausgrid and Endeavour Energy have fewer DER constraints issues, and still rely solely on inverters to manage these issues.[60] None of the distributors has visibility of when these inverters trip.[61]

Endeavour Energy indicated that it currently schedules minor works to boost hosting capacity.[62] However, this may not be sustainable as DER uptake increases because the need to boost hosting capacity will also increase.

We consider that these findings demonstrate the need for regulation of DER to ensure distributors can invest in adequate hosting capacity.

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55 *Distributors' incentives to efficiently incur DER export expenditure report* dated 22 July 2020, HoustonKemp Economists, p 49. HoustonKemp considered that this was evident through issues such as the absence of a minimum service standard for hosting capacity.
56 As above, p 8.
57 As above.
58 *Distributors' incentives to efficiently incur DER export expenditure report* dated 22 July 2020, HoustonKemp Economists, p 7.
59 As above, p 8.
60 As above.
61 As above.
62 As above.

6.3 How could reliability standards be used to create those incentives?

HoustonKemp analysed several regulatory options to create incentives for the distributors to increase hosting capacity for customers, including two that could be effected through changes to the reliability standards in their operating licences:

1. An information disclosure option that required distributors to publish DER-related information
2. A new guaranteed customer service standard that would compensate individual DER customers that receive below a minimum threshold of network access to export electricity.[63]

We consider that introducing an information disclosure requirement would be a prudent starting point for more effectively integrating DER into the network. It would provide data to better understand the level of DER penetration, its impact on the network and customers, and the materiality of that impact. Such information would also be valuable in determining the necessary amount of regulation of DER and to inform customer decisions on investing in DER.

We note Endeavour Energy's submission that it would be premature to make changes to the licence without awaiting the outcomes of the national reform efforts that are currently underway.[64] However, we consider that an information disclosure requirement strikes a good balance between awaiting outcomes from national processes (which may take some time to finalise), and potentially prematurely regulating DER through the licence conditions.

We agree with AEMO's view that "the ability to efficiently integrate DPV[65] generation within networks is severely hampered by a lack of visibility of the LV network" and the need for investment to improve network visibility should be promptly addressed.[66] We consider that an information disclosure requirement would significantly contribute to resolving this issue.

Box 6.1 below sets out our proposed licence condition to effect an information disclosure requirement. We invite stakeholders comment on this proposal.

We do not consider the second option, introducing a new guaranteed customer service standard that would compensate individual DER customers that receive below a minimum threshold of network access to export electricity, is appropriate at this stage. Without a clear understanding of DER constraints issues and their materiality, any regulation would be premature and potentially uninformed.

63 As HoustonKemp was engaged before national DER-related reforms were initiated, it also considered four options that would need to be affected at the national level. These include introducing a DER expenditure incentive margin option; removing the prohibition on distributors levying DUOS charges on DER exports; classifying DER exports as an alternative control service and removing these services from the standard control service revenue cap; and introducing a DER component to the AER's STPIS mechanism. For more information, see HoustonKemp Report on our website.

64 Endeavour Energy, Submission to the Issues Paper, April 2020, p 12.

65 Distributed Photovoltaics is the process that converts solar energy into electricity directly through PV modules.

66 AEMO, Renewable Integration Study: Part 1 report, 2020, p 40.

Box 6.1 Proposed DER information disclosure licence condition

Ausgrid, Endeavour Energy and Essential Energy (Licence Holders) must publish the following information on their website in accordance with the due dates noted in the reporting manual[a]:

- the number of DER connected to the Licence Holder's distribution network;
- the volume of electricity exported into the Licence Holder's distribution network from DER;
- the top ten areas by postcode in the Licence Holder's distribution district that have the highest levels of DER penetration by reference to volume of electricity exported and number of units and/or systems;
- the volume of electricity that could not be produced due to insufficient hosting capacity of the Licence Holder's distribution network;
- the number of complaints from DER customers by reference to postcode relating to constraints impacting the export of electricity from DER;
- the number of complaints from customers without DER affected by voltage issues or exceedance of thermal capacity limits due to DER;
- the number of customers that are subject to static limits or who are refused connection to the distribution network due to DER;
- the number of DER customers that are actively being curtailed from exporting any electricity via a total static limit; and
- the number of DER customers that are actively being curtailed from exporting some electricity via a partial static limit; and
- the level of operating and capital expenditure by the Licence Holder that is primarily for the purpose of addressing network constraints on DER exports (including justifications for expenditure options).

a: The reporting manual (draft) is available on the IPART website.

Note: The NER deem some information held by distributors to be confidential (even if in some cases the inherent nature of the information is not confidential). We will further consult with the distributors on the confidentiality of any information and such information would be excluded from publication.

6.4 How would the licence requirements interact with the national incentives?

We consider that our recommended information disclosure requirement would complement the DER register AEMO introduced in May 2020.[67] This register stores information about DER devices installed on-site at residential or business locations. After registration of this information, AEMO has an obligation to provide quarterly reports on the number of DER devices installed across the National Electricity Market (NEM).

We note that the intent of our recommended information disclosure requirement is similar to that of the DER register. However, the information we are proposing the distributors report on is more detailed, and extends to customer complaints and curtailment data. We consider that this will address the lack of visibility across the network and also assist customers in making decisions on whether or not to invest in DER. In our view, the information disclosure requirement would complement the DER register in its effort to increase DER visibility across the NEM.

We will monitor the progress of national reforms to DER and continue to assess whether any additional regulation is required through the licence conditions. For example, if any national measures are introduced, we will review the necessity of the reporting requirement to ensure that it is not duplicative. Box 6.2 below summarises some of these national reform processes which are currently underway.

67 https://aemo.com.au/en/energy-systems/electricity/der-register

Box 6.2 National reform processes related to DER

Distributed Energy Integration Program (DEIP)

ARENA is leading a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of customers' DER for all energy users. The program is divided into multiple work streams. The Access and Pricing work stream has produced a report making recommendations concerned with access rights, the appropriateness of network pricing and the potential introduction of a DER incentive scheme. The Outcomes stream has highlighted the need to create additional obligations and/or incentives for distributors to provide hosting capacity, which will be the subject of a future AEMC-initiated study.

Proposed rule changes

Three rule change proposals on DER were recently submitted to the AEMC for consideration. The proponents for the rule changes are SAPN, the St Vincent De Paul Society Victoria, the Total Environment Centre, and the Australian Council of Social Services. The AEMC has published a consultation paper on the proposal and aims to publish its final determination by 25 February 2021.[a]

The proposed rule changes focus on three key areas:

- Updating the regulatory framework to reflect the community expectation for distributors to efficiently provide export services to support DER
- Promoting incentives for efficient investment in, and operation and use of, export services
- Enabling export charges as a pricing tool to send efficient signals for future expenditure associated with export services, reward customers for actions that better utilise the network or improve network operations, and allocate costs in a fair and efficient way.

a: AEMC Consultation Paper, Distributed Energy Resources Integration – Updating Regulatory Arrangements, 30 July 2020, page 5.

Sources: https://arena.gov.au/knowledge-bank/distributed-integration-program-overview/ and AEMC Consultation Paper, Distributed Energy Resources Integration – Updating Regulatory Arrangements, 30 July 2020.

7 Standalone power systems (SAPS)

Our terms of reference require that we have regard to changes in the licence that would assist the distributors to evolve and take advantage of new technologies, such as stand-alone power systems (SAPS), which may offer more cost-effective solutions than traditional network investment.

At the most basic level, a SAPS is any system that is not connected to the National Electricity Market's interconnected grid and generates a supply of electricity for customers. The term is used to cover both microgrids, which supply electricity to multiple customers, and individual power systems, which relate only to single customers.[68]

At present both the licences and the national economic regulation framework for distributors exclude SAPS. However, the AEMC has developed a regulatory framework that, when implemented, will mean that distributor-led SAPS are treated as an extension of the traditional distribution network.[69] We understand that the NSW Department of Planning, Industry and Environment (DPIE) is currently considering amendments to NSW legislation that would be required to incorporate distributor-led SAPS into the distributor licensing framework. We have made our draft recommendations with the expectation that this will happen by 2024 when our draft licence amendments would apply, and encourage the NSW Government to progress required changes within the national framework and at the state level.

This chapter discusses the current and future arrangements for SAPS in the licence standards. The section below gives an overview of our draft recommendations. We then discuss the types of SAPS that are used, the current legislative framework, and how the licence conditions should be used to protect SAPS customers in receiving minimum levels of reliability.

7.1 Overview of our draft recommendations

Whilst distributor-led SAPs are not common in NSW, we expect their use to expand as the legislative frameworks accommodate their use, and new technology improves efficiency and competitiveness with the traditional network infrastructure.

We consider that customers of distributor-led SAPS should receive the same customer protections afforded by the licence as other customers of the distributors. This consists of applying:

- The individual feeder standard for microgrids with high voltage distribution lines.
- The individual feeder standards with a default length of 200km for all other SAPS.

68 Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, p i (accessed 8 October 2020).

69 AEMC, *Review of the regulatory frameworks for stand-alone power systems – Priority 1 Final Report*, 30 May 2019. (accessed 8 October 2020).

- The guaranteed service levels to all SAPS customers on the deemed standard connection contract.

Customer protection is particularly important as distributors can move customers from the network to a SAPS without explicit consent.[70]

7.2 What types of SAPS do our recommendations apply to in NSW?

7.2.1 Reliability standards cover distributor-led micro grids and individual power systems

Distributors and third-parties can operate standalone power systems. Our focus is on SAPS that are operated by or on behalf of the distributors. However, private companies may own and operate standalone power systems independent of a major distribution company - these are referred to as third-party SAPS by the AEMC – and are not covered by the reliability standards for the distributors.

There are two main categories of SAPS:

- **Individual power systems** supply a single customer.[71] These systems are likely to be relatively common (in the context of standalone power systems). An individual power system, typically, will be installed on the customers' property.
- A **microgrid** is a standalone power system that supplies multiple customers.[72] This covers a wide range of possibilities, providing electricity to:
  - As few as two premises,
  - As many as a large town (eg, the Mount Isa-Cloncurry network is sometimes referred to as a microgrid,[73] it supplies over 10,000 customers with generation primarily from a gas fired power plant).

Microgrids are more varied than individual power systems. However, because electricity is transported between sites it is typically easier to delineate between generation and distribution infrastructure in microgrids.

70 Under section 38 of the *National Electricity Retail Law* NSW, a customer's explicit informed consent is required if the customer is to be transferred to a new retailer or a new market retail contract. The AEMC's recommended SAPS service delivery model does not require either of these changes upon transitioning a customer to a distributor-led SAPS. Nor would a transition to a SAPS be treated as a disconnection. Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, p 46. (accessed 14 October 2020).

71 Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, p I. (accessed 8 October 2020).

72 Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, p I. (accessed 8 October 2020).

73 See Infrastructure Australia, *Australian Infrastructure Audit 2019,* p 534. We note that the Mount Isa network is regulated by the AER under the Chapters 4 and 11 of the NER.

7.2.2 Growth in SAPS is expected as solar and batteries improve efficiency

Distributor-led micro-grids are not common in NSW due to the extensive built network, legislative barriers and lack of efficiency. However, Essential Energy has had some recent experience with emergency SAPS and is trialling some micro-grids. The NSW distributors estimated, for the AEMC, that they could supply over 2,000 customers by 2030 mostly in the Essential Energy footprint.[74]

There are three reasons why distributors may seek to employ SAPS:

- To permanently replace grid connection, particularly on the fringe of the grid. The cost of solar and batteries have made SAPS more cost competitive with grid connections and it may be more cost effective for distributors to either:
  - Replace existing grid connections with SAPS, and
  - To offer a SAPS to new customers that seek an electricity connection as an alternative to a grid connection.
- As emergency supply, for instance if bushfire, floods or other natural disasters cut electricity to an area. These could be in place for an extended period as the network is rebuilt.
- As a back-up to grid connection. This approach allows a grid connected customer to maintain electricity during an outage.

Essential Energy has identified that the benefits of SAPS include lower network costs, network resilience and reliability for customers on the fringe of the grid or in heavily vegetated areas, ie, SAPS can provide:[75]

- An overall reduction in network costs as SAPS become increasingly more efficient than the building and maintenance of traditional network infrastructure.
- A reduction of bushfire risk and the cost of risk mitigation activities by removing long lines through bushland.
- Better reliability for customers surrounded by bushland, as lines can be impacted by fires.
- Potentially faster and more cost effective fault rectification.

Ausgrid also noted that SAPS may be an effective way to invest in improved network resilience.[76]

Boxes 7.1, 7.2 and 7.3 below summarise some examples of the ways in which distributors use SAPS.

74 Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1*, Final Report, 30 May 2019, p iii.
75 Essential Energy submission to IPART Issues Paper, May 2020, pp 15, 19.
76 Ausgrid, submission to IPART Issues Paper, May 2020, p 6.

Box 7.1 Essential Energy's permanent SAPS at Bulahdelah

In 2018, Essential Energy commissioned an individual power system for a customer within the Myall Lakes National Park. This customer was served by a 5.5km spur. Supplying this customer had cost Essential Energy over $100,000 in replacement assets and $150,000 in vegetation management over 9-years. Over the same period, the customer experienced 70 hours of interruption over 25 separate outages.

Since the SAPS was installed there have been two outages; one related to the customer installing a large water heater that required a settings change, and the other due to a mechanical fault in the generator – both of these outages were initially rectified by switching back to mains power and resulted in crucial learnings for SAPS. Essential Energy estimates that the lifetime cost for this SAPS will be around $700,000.

Source: Information provided by Essential Energy to IPART February 2020

Box 7.2 Essential Energy's Peak Alone SAPS

During the 2019-20 bushfire season Essential Energy deployed a rapid response SAPS to the Peak Alone telecommunications site. The rapid response SAPS consists of:

▼ One 12 kilowatt (kW) solar array

▼ One 4kW solar array

▼ Six 13.5 kilowatt-hour (kWh)/Total 81kWh batteries (Tesla Powerwall 2)

▼ Two 13.5kWh/ Total 27kWh batteries (Tesla Powerwall 2), and

▼ Back-up diesel generation.

The solar and batteries reduce the need to refuel the generator. Before the bushfire the Peak Alone site was supplied by a 4.1km spur, with an average 20% grade slope.

The rapid response SAPS was provided free of charge by Resilient Energy Collective.

Source: Information provided by Essential Energy to IPART August 2020

Box 7.3 SAPS as back-up to grid connection

In response to our consultation on customer service standards:

▼ Endeavour Energy noted that it may seek to provide generation and/or storage to worst served customers on the network.

▼ Essential Energy noted that it was looking at the capability of 'islanding' a town to respond to distribution or transmission faults. This would allow a town to maintain electricity when otherwise it would experience an outage.

Neither of these possible approaches are technically SAPs. However, they share the same technology as SAPs and pose similar regulatory challenges

7.3 What is the current legislative framework for SAPs in NSW?

NSW electricity distributors are primarily regulated by the:

- *National Electricity Law* and *National Energy Retail Law* and their associated rules and regulations.
- *Electricity Supply Act* NSW and its associated regulations and licences.

The regulations for NSW electricity distributors were designed in the context of separating generation activities from distribution activities. Accordingly, regulatory barriers currently prevent distributors from expanding the use of SAPS.

7.3.1 Limitation of the current electricity regulatory framework

The *National Electricity Rules* under the *National Electricity Law* regulate the activities of NSW distributors with respect to the economic regulation of their distribution systems that form part of the interconnected national electricity grid. The Rules also restrict the extent to which a regulated distribution business can be involved in electricity generation and sale of electricity to customers. So SAPS provided by distributors to discharge their obligations as regulated distribution businesses does not currently fit well within the national electricity framework. Nor is it entirely clear what scope there is to address this under the current NSW licensing framework.

In practical terms, this means that distributor-led SAPS fall outside this framework and legislative amendments are required to clearly incorporate these SAPS into the regulatory frameworks that currently regulate NSW distributors.

7.3.2 The national regulatory framework is expected to incorporate SAPS before 2024

The AEMC has proposed law and rule changes that will allow both distributor-led SAPS and third-party SAPS.[77] The exact timing of the proposed changes is unclear, but we expect that these changes would take effect before 2024, when our recommended licence changes are expected to apply. We note that the changes to SAPS were not included in the AER, AEMC and AEMO's joint letter outlining regulatory priorities to the Chair of the COAG Energy Council in April 2020.[78]

Essential Energy noted that the NSW Government should have the right jurisdictional arrangement in place so that SAPS can be deployed as soon as the national framework is amended. Ausgrid also noted the importance of minimising delays when opting-in to the national framework.[79] The Clean Energy Council considered that the NSW Government should have the option to opt-in to the national framework.[80]

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77 See https://www.aemc.gov.au/sites/default/files/documents/updating_the_regulatory_framework_for_distributor-led_stand-alone_power_systems_final_rules_28_may_2020.pdf (accessed 14 October 2020).

78 AER, AEMO, and AEMC, Prioritising implementation timeframes: a more detailed view, Letter to The Hon Angus Taylor MP, (accessed 8 October 2020).

79 Ausgrid submission to IPART Issues Paper, May 2020, p 8.

80 Clean Energy Council, submission to IPART Draft Terms of Reference, February 2020, p 1.

7.3.3 It is best to coordinate NSW legislative change with national legislative change

We considered whether the NSW Government could implement transitional legislation to allow licence regulation of distributor-led SAPS by amending existing legislation. This may involve, for example, amendments to the *Electricity Supply Act 1995 (NSW)* and/or the *National Energy Retail Law (Adoption) Act 2012* to allow the NSW licences to cover distributor-led SAPS.

However, we do not recommend making any legislative changes to allow distributor-led SAPS before the national adoption of the AEMC's proposed framework. Amending NSW law does not amend the NER, and means that the AER would not be responsible for the economic regulation (including price regulation) of distributor-led SAPS. The NSW Government would then need to decide whether to:

- Seek a rule change to make the AER responsible for the economic regulation of distributor-led SAPS in NSW
- Set up a local regulator for the economic regulation of SAPS, or
- Leave SAPS without economic regulation.

It is preferable that the NSW legislation be amended when there is national implementation of the AEMC's proposed legal and regulatory framework for distributor-led SAPS.

Draft recommendation

24 The NSW Government continue to progress legislative changes to incorporate distributor-led SAPS within the NSW Electricity Supply Act framework as well as incorporate distributor-led SAPS into the National Energy Retail Law (New South Wales), on national implementation of the AEMC's proposed legal and regulatory framework.

7.4 How should the distribution licences protect SAPS customers?

As the timing and form of any legislative reforms to enable growth in SAPS is uncertain, we are unable to make precise recommendations as to the form that SAPS licence conditions would need to take.

However, we consider there are strong consumer protection reasons for providing guidance on the reliability standards that should apply when legislative reform to incorporate NSW distributor-led SAPS occurs. As noted above, we expect that the AEMC's framework will be in place by the time the revised reliability standards commence operation (ie, 1 July 2024).

7.4.1 The network reliability standards should apply to all distributor-led SAPS

Our draft recommendations for grid-connected customers (see Chapter 2) is to continue to set a reliability standard for:

- An individual feeder and
- Guaranteed service levels and payments.

We are proposing that reliability standards also extend to distributor-led SAPS so that customers would have the same level of regulatory protections as if they were supplied off the grid. We understand that modern SAPS typically provide more reliable supply. Our draft recommendation is consistent with the AEMC's principle that no customer should be worse off after being transitioned from a grid connection to a SAPS.[81] A number of submissions to our Issues Paper agreed with this principle.

EWON supported the extension of standards to SAPS customers, noting that this would ensure all customers have the same consumer protections, and it would provide a regulatory standard against which an ombudsman could assess a complaint.[82]

PIAC considered that it was not appropriate or necessary to develop SAPS-specific reliability standards.[83] Instead, reliability standards specific to the circumstances of each SAPS could be applied in due course.[84] Endeavour Energy also supported SAPS-specific reliability standards.[85]

While each SAPS would service relatively few customers compared to the feeders that the standards currently apply to, we consider it is important to have service standards in place to prevent further delay in the roll-out of SAPS. We also consider that implementing the same standard is consistent with the principle of no SAPS customer being worse off than if they were connected to the grid.

It also reflects that the role of reliability standards is to provide customer protection. We consider that distributors will often have significant market power over customers in providing distributor-led saps, under the AEMC's proposed framework. This is most clear where distributors move existing customers from network connections to distributor-led SAPS without customer consent.

In theory the SAPS market will be competitive. Allowing competition and innovative approaches that lead to customer choice can improve efficiency. However, new/third-party suppliers need to be able to freely enter and compete on a level playing field, subject to a well-developed regulatory framework to protect customers' interests.

81 Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, pp 40-41 (accessed 14 October 2020).
82 EWON, Submission to Issues Paper, April 2020, p 3.
83 PIAC submission to IPART Issues Paper, May 2020, p 5.
84 As above.
85 Endeavour Energy submission to IPART Issues Paper, April 2020, p 12.

7.4.2 Extending the individual feeder standard to SAPS

We recommend applying the individual feeder standards to SAPS. This would require some changes to the licence when the AEMC's proposed framework for distributor-led SAPS is adopted.

How we apply the individual feeder standard depends on the characteristics of the SAPS:

1. Some large microgrids will have high voltage power lines that resemble feeders. We propose that individual feeder standards should apply to these high voltage power lines as if they are feeders.[86]
2. Where SAPS replace the need for long feeders we propose setting the default SAIDI and SAIFI for SAPS equal to the standards for a 200km feeder.

Draft recommendations

25 At the time of commencement of relevant enabling legislative changes, the proposed reliability standards should be extended to distributor-led standalone power systems as follows:

– the individual feeder standards to apply to microgrids with feeder-like high voltage distribution lines

– the individual standards with a default length of 200km to apply to all other distributor-led standalone power systems

– apply the guaranteed service levels and payments to distributor-led standalone power systems consistent with how they apply to grid connected customers.

7.5 What guaranteed service levels and payments should apply to distributor-led SAPS?

The current 'customer service standards' require a compensation payment be made to individual customers if they experience outages exceeding particular duration or frequency thresholds. Our draft recommendations for grid connected customers is to replace these with guaranteed service levels and payments consisting of three levels of thresholds and changing the way the payment is calculated.

Generally, we see no reason why either the standards or the payments should differ for SAPS customers. However, there is uncertainty around whether SAPS customers will fall under the deemed standard connection contract with the distributor once legislative changes take place.

Draft recommendation

26 In progressing legislative amendments, the NSW Government should ensure that customers of distributor-led SAPS receive the same customer protections afforded by the licence as other residential and business customers of the distributors.

86 To achieve this, the Minister could amend the definition of feeder in the licence to incorporate lines operating at, or over, 1 kV and generally at, or below, 22 KV within a SAPS.

7.5.1 Implementation of guaranteed service levels and payments will depend on the final legislative framework

The implementation of our recommended standards is related to the deemed standard connection contract that distributors have with their grid-connected customers. When a customer connects to the grid, the deemed standard connection contract specifies some obligations and responsibilities for both parties.

At this stage, it is unclear whether the proposed legislative changes to support SAPS intend for the SAPS customers to typically be covered by the deemed contract, or whether they will be expected to enter negotiated contracts. We also understand that some SAPS customers (such as businesses with particular electricity needs) may prefer to enter a negotiated contract with their distributor and be able to negotiate around price and reliability with supply being tailored to their requirements.

However some potential SAPS customers may seek the protections of being supplied under a deemed contract and receive a relatively standard service. We seek feedback on whether guaranteed service levels (and therefore the compensation payments) should apply to customers on negotiated contracts. (See also further discussion in section 5.2.2.)

8 Commencement, compliance and further reviews

The final step in our approach involved establishing the compliance and monitoring framework for the reliability standards, including when any new standards should take effect, how often distributors should be required to report against the standards (and how these reports should be audited), when the standards should be reviewed and who is best placed to conduct future reviews.

The sections below gives an overview of our draft recommendations and further detail on each of these areas.

8.1 Overview of draft recommendations

We are recommending our changes to the reliability standards take effect from 1 July 2024, to align with the beginning of the next regulatory control period. This timing would ensure both the distributors and the AER can take the revised standards into account in the next regulated revenue review. It would also give the distributors time to engage and consult with their customers on what the changes might mean for services and prices, to inform their next regulated revenue submission to the AER.

However, in the case of DER reporting standards, we consider there are benefits to the distributors providing the required information from earlier than 2024. Therefore, we recommend that the distributors commence publishing this information on a voluntary basis from 1 July 2021 until such a time that the licence is updated to reflect these requirements.

We also consider there is scope to streamline the distributors' reporting and auditing requirements. They are currently required to provide quarterly reports to IPART on their compliance with the reliability standards and undertake annual independent audits of this compliance. To ensure that the costs of reporting and auditing are commensurate with the benefits, we consider that it would be appropriate for now to require annual reports on compliance and to give IPART the discretion to decide on the frequency and scope of audits based on reported reliability performance.

We are also recommending the standards be periodically reviewed every five years, to inform each five-year regulatory control period.

8.2 When should the licence conditions begin to apply?

We recommend that the licence conditions apply from 1 July 2024, which is the beginning of the next revenue determination period.

This commencement date gives the distributors an opportunity to engage and consult with their customers on what the changes might mean for services and prices, to inform their next regulated revenue proposal to the AER, and to amend their internal systems to manage the changed standards. The AER can take any revised reliability requirements into account at the next regulated revenue review.

As noted in Chapter 7, we consider there are benefits to the distributors providing the required information from 1 July 2021. Therefore, we are recommending changes to the current reporting manual to take effect from this time.

Draft Recommendation

27 That the recommended licence conditions come into force on 1 July 2024.

8.3 How should compliance be monitored?

Self-reporting and independent audits are important features of a compliance regime. For our compliance activities, we prefer to take a risk-based approach, balancing the regulatory burden of compliance arrangements with the likelihood of non-compliance and risks to the community.[87]

Under the current licences, distributors are required to report quarterly to IPART on their performance against reliability standards, and performance must be independently audited by 30 September each year. Our draft recommendations are to reduce the reporting and auditing requirements.

8.3.1 Distributors should report their compliance to IPART annually

Our draft recommendation is that annual compliance reporting by the distributors is more appropriate than quarterly reporting. Since IPART has been monitoring compliance with the licence conditions, distributors have shown a relatively high level of compliance with the current reliability conditions.[88] We therefore consider that a shift from quarterly to annual reporting would be relatively low risk. The change would commensurately reduce the reporting burden on distributors.

IPART maintains a reporting manual which sets out more detailed reporting requirements and can include the timing of reporting. The draft licence conditions allow the Tribunal to adjust the timing of the reporting requirements through its reporting manual if it finds cause for more or less frequent reporting. A move from annual reporting would include a stakeholder consultation process.

In response to our Issues Paper, all respondents on this topic agreed with the change to annual reporting requirements rather than quarterly, and there was support for IPART to have increased flexibility.[89] Business NSW considered that such a change would increase the distributors' engagement with reliability reporting.

87 For more information about our approach to risk-based compliance, see our Compliance and Enforcement policy - https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/energy-network-regulation-policy-compliance-and-enforcement-policy/compliance-and-enforcement-policy-december-2017.pdf.

88 See for instance, our *Annual Compliance Report - Energy network operator compliance during 2018-19*, pp 13-14.

89 For instance, PIAC, submission to IPART Issues Paper, May 2020, p 7; Endeavour Energy submission to IPART Issues Paper, April 2020, p 14; Ausgrid submission to IPART Issues Paper, May 2020, p 25; Essential Energy submission to IPART Issues Paper, May 2020, p 24.

Draft Recommendation

28 That the distributors provide annual reports to IPART on their compliance with reliability standards, with flexibility for IPART to adjust report timing through its reporting Manual If IPART considers more or less frequent reporting is appropriate.

8.3.2 Current quarterly investigation requirements should be maintained

The current licence requires distributors to review individual feeder SAIDI and SAIFI performance on a quarterly basis, and where the standards are breached, to investigate and undertake rectification action where it is economic to do so. Currently, these investigations are reported to us on a quarterly basis.[90]

We consider the investigative requirement is valuable to ensure the timely identification of underperforming feeders and potential rectification to provide better customer outcomes. Our draft recommendation is to maintain this obligation. However, the outcomes should be reported to IPART annually rather than quarterly. Again, the frequency of this reporting could be able to be amended via the reporting manuals if deemed appropriate.

Draft Recommendation

29 That the distributors continue to complete quarterly investigations of individual feeders and direct connections that do not meet the SAIDI and SAIFI standards, and report these to IPART annually.

8.3.3 IPART should have discretion regarding audit frequency and scope

We apply a similar risk-based approach to compliance auditing (where legalisation allows for it). As noted by Essential Energy, over the past few years, the annual audits have not highlighted any issues of significant concern.[91]

The current licence conditions require an annual independent, 'limited assurance' audit be undertaken. We consider it would be more appropriate to provide the Tribunal with the discretion to call for an independent audit with a tailored audit scope as it finds appropriate. Audits would be based on an assessment of risk and likelihood of non-compliance and could for instance, be in response to information received about failure to comply or possible failure to comply.

This is a more efficient approach than the current approach as it allows for individualised auditing regimes for the three distributors based on their particular circumstances, compliance history and behaviour. We expect this will lead to a reduction in regulatory cost for the distributors.

Draft Recommendation

30 That the licence conditions allow IPART as the licence administrator, the discretion to determine the frequency and scope of independent compliance audits, and that the Tribunal does this using a risk-based approach.

90 Condition 7.3 of the Distributors licence under the Electricity Supply Act 1995, granted to Ausgrid, Endeavour Energy and Essential Energy.

91 Essential Energy submission to IPART Issues Paper, May 2020, p 24.

8.4 How often should the standard be reviewed?

We recommend the final standards be reviewed periodically. There are several reasons for periodically revisiting the standards:

- To assess the impact of the new standards on customer experience, including changes in costs (increase or decrease) with empirical evidence after implementation.
- To update inputs to the modelling work if needed. The modelling involved a range of data for which better estimates or data sources may become available. For example, the estimates of VCR for different customer groups or locations may change due to consumer sentiment. Stakeholders (in particular the distributors) will have an incentive to develop better data sources, given that these data are now used to establish reliability standards.
- To adapt to new legislation and technology that may be in place, which is particularly likely for SAPS. There is merit in ensuring the standards remain relevant, efficient and effective.
- The methodology we have adopted is innovative and is likely to benefit from development over time.

We consider that reviews of the standards should occur at an appropriate time to allow any savings (or costs) arising from revisions to be incorporated into the distributors' future planning and revenue proposals to the AER, and into AER determinations. As such, we recommend the first review should be completed by June 2027.

Reviews should occur on a 5-yearly basis thereafter. We consider 5-yearly reviews find a balance between providing time for the standards to be incorporated into the distributors' processes, limiting regulatory burden, and achieving the best outcomes for consumers. It also aligns with the AER revenue determination timing. Endeavour Energy supported a 5-yearly review.[92]

As licence administrator under the Electricity Supply Act, IPART is required to report to the Minister on a 5-yearly basis with its view on whether a review of licence conditions should be conducted.[93] This provides a suitable mechanism for IPART to trigger reviews of the reliability standards. As part of licence reviews, IPART intends to review the adequacy of the reliability licence conditions, with the next review to be completed by June 2027, and subsequent reviews 5-yearly thereafter.

92 See for instance, Endeavour Energy submission to IPART Issues Paper, May 2020, p 14.
93 Under Clause 11, Schedule 2 of the *Electricity Supply Act* 1995.

Appendix

A Terms of Reference

I, Gladys Berejiklian, Premier of New South Wales, under section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992*, refer to the Independent Pricing and Regulatory Tribunal (IPART) for investigation and report the following matter.

IPART is to provide a report to the Premier and the Minister for Energy and Utilities recommending:

1. any changes to electricity distribution reliability standards for the NSW distribution network businesses that could deliver bill savings to NSW electricity customers; and

2. any other measures that could be imposed on or implemented by the NSW distribution network businesses within the current regulatory framework that would be likely to reduce network prices and are consistent with the National Electricity Objective.

In making recommendations as to electricity distribution reliability standards, IPART is to apply an economic assessment to evaluate how efficient network capital and operating costs would vary with different levels of reliability, and then compare the level of expected capital and operating expenditure against the value that customers place on reliability.

In undertaking the review, IPART is to have regard to:

1. the objective of the New South Wales Government to improve electricity affordability while maintaining a reliable and secure network;
2. the potential impact on customer bills, assuming current regulatory arrangements, from:
   a) any change in the distribution network reliability standards;
   b) any other measures that would reduce network prices and are in the long term interests of customers;
3. the value customers place on having a reliable and secure network including the AER's VCR estimates to be published by 31 December 2019 and any other published values;
4. changes that would assist the NSW distribution networks to evolve and take advantage of new technologies that may offer more cost-effective solutions than traditional network investment (such as a stand-alone power systems);
5. the differences in the costs and benefits of delivering reliable network services to different networks and different parts of the network, including CBD, rural, and regional areas;
6. the NSW distribution network businesses' safety and security obligations;
7. a stable regulatory environment;
8. consistency with national incentives and obligations with respect to distribution reliability;
9. the AER's regulatory determinations for the 2019-24 regulatory period;

10. the relevant recommendations of the 2018 State Infrastructure Strategy and the Australian Competition and Consumer Commission's Retail Electricity Price Inquiry and reports which outline the pressures and experiences felt by NSW consumers such as Turning off the Lights: The Cost of Living in NSW by the NSW Council of Social Services and Close to the Edge by PIAC.

IPART is to undertake public consultation for the purposes of its investigation.

IPART is to release a draft report for consultation within 6 months of the publication of the AER's final VCRs and release a final report within four months of the draft report.

The Hon Gladys Berejiklian MP
Premier

Dated at Sydney 26/2/19

B Context for this review

To undertake analysis and provide input to this review, it is important to understand the context in which the distributors operate. The sections below provide more information on the following:

- The role of the distribution networks
- The current reliability standards and the businesses' historical performance against them
- The requirements of the NER and the AER and how they impact on distributors' reliability.

B.1 Role of distributors in the electricity supply chain

Distribution networks are a key part of the electricity network system. As Figure B.1 illustrates, they take high voltage electricity from the transmission network, transform it to a lower voltage and deliver it to residential, commercial and industrial customers.[94]

Outages which cause an interruption to a customer's electricity supply can be caused by a lack of generation supply, transmission network outages or distribution network outages.[95] While historically the distributors have provided a high level of reliability, analysis by the Reliability Panel shows that 94 per cent of interruptions to customer supply (both planned and unplanned) in the past decade were caused by distribution network outages.[96]

In NSW, there are three licensed distributors:

- Ausgrid distributes electricity across Sydney, the Central Coast and Hunter Valley, and is the largest distributor by customer numbers (see Table B.1)
- Endeavour Energy distributes electricity across Sydney's Greater West, the Blue Mountains, Southern Highlands, the South Coast and Illawarra[97]
- Essential Energy distributes electricity to the remaining 95% of NSW and some parts of Southern Queensland.

94 Distributors also deliver electricity to a small number of customers who are not connected via distribution feeders. These are typically large industrial customers.

95 AER, Values of Customer Reliability - Final Decision, 2019, p 4.

96 AER, Values of Customer Reliability - Final Decision, 2019, p 4.

97 Endeavour Energy Distribution Annual Planning Report, 2019 DAPR, December 2019, p 6.

Figure B.1 Electricity supply chain

Electricity is generated through various sources including water, wind, sun and fossil fuels. The generated electricity is converted using transformers to very high voltages for transfer over long distances.

The transmission network then transfers the electricity at very high voltages of up to 500 kV (1000 volts (V) = 1 kV) to bulk supply substations (large load centres) where it is transformed to lower voltages of up to 132 kV. The electricity then goes into the distribution network to supply zone substations through subtransmission feeders (high voltage power lines). A substation is electrical infrastructure which contains transformers that use electromagnetic induction to either increase or decrease the voltage of the electricity as required. Some high voltage customers are supplied directly from zone substations.

Otherwise, it is at the zone substation that the electricity is transformed from voltages of up to 132 kV to lower voltages, generally at 11 kV for supply to distribution substations. The overhead wires or underground cables that transfer the electricity from the zone substation to the distribution substation are what we refer to as feeders for the purposes of this review.

The distribution substations transform the electricity to even lower voltages that are suitable for domestic use. That electricity is then delivered to properties through the low voltage network that is made up of overhead poles and wires, and underground cables.

Table B.1 NSW distributor network characteristics

	Ausgrid	Endeavour Energy	Essential Energy
Land area (square km)	22,275	24,980	737,000
Feeders	2,373	1,556	1,465
Customers	1.8 million	1.0 million	855,000
Zone substations	182	164	339
Distribution substations	32,301	32,349	138,539
Power poles	511,656	429,000	1,390,806
Total length of power lines (km)	44,000	59,300	183,612

Note: The distributors have reported that some of these figures are approximated and Essential Energy's total length of powerlines refers to overhead lines only.

Source: Ausgrid Distribution and Transmission Annual Planning Report - December 2019, Endeavour Energy Distribution Annual Planning Report 2019 DAPR - December 2019, and Essential Energy Asset Management Distribution Annual Planning Report - December 2019.

Distribution network charges account for about a third of the average electricity bill for residential and small business electricity customers.[98] Other components of the bill include wholesale electricity costs, transmission network charges, environmental policy costs and retail costs.

B.2 Current reliability standards

Reliability refers to the extent to which customers have a continuous supply of electricity.[99] Reliability standards establish the level of reliability that a distributor is required to provide.

B.2.1 Distributors' licences contain four reliability requirements

The Minister for Energy and Environment (the Minister) has issued each distributor with an operating licence which details the requirements they must meet in order to operate a distribution network in NSW. There are currently four requirements that impact on reliability:

- **Network overall reliability standards**: require the distributors to ensure that the average duration and frequency of unplanned interruptions over the whole network do not exceed specified levels. These overall standards apply to different feeder types[100] (Sydney CBD, urban, short-rural and long-rural feeders) and are measured using two indices:
  - System Average Interruption Duration Index (SAIDI), calculated as the average of the sum of the durations of each sustained customer interruption (measured in minutes), divided by the total number of customers.
  - System Average Interruption Frequency Index (SAIFI), calculated as the total number of sustained customer interruptions divided by the total number of customers.

98 AER, Final Decision – Ausgrid distribution determination 2019-24, p 17, Accessed 11 February 2019
AER, Final Decision – Essential Energy distribution determination 2019-24, p 8
AER, Final Decision – Endeavour Energy distribution determination 2019-24, p 8

99 AEMC, Fact sheet: what is transmission reliability? 2013, Accessed 20 February 2020.

100 Feeders are the lines that transfer electricity from a distribution substation to a distribution transformer.

Certain types of interruptions that are generally considered outside the control of the distributors are excluded from both SAIDI and SAIFI (see Box B.1).

- **Individual feeder standards**: require the distributors to ensure that the average duration and frequency of unplanned interruptions on each feeder do not exceed specified levels.

  These levels are also measured using SAIDI and SAIFI for each feeder and disregard excluded interruptions.

  The distributors are required to monitor performance of individual feeders, consider whether it is economically feasible to improve performance on feeders failing to meet reliability standards and report to the Minister where they determine that it is not feasible to bring performance up to the required standard.

- **Individual customer standards:** require the distributors to ensure that the average duration and frequency of unplanned interruptions for some large industrial customers that are directly connected via sub-transmission feeders do not exceed specified levels.

  As is the case for individual feeder standards, the distributors are required to monitor performance of individual customers, consider whether it is economically feasible to improve performance where they are not meeting reliability standards and report to the Minister where they determine that it is not feasible to bring performance up to the required standard.

- **Customer service standards**: provide for eligible customers to apply for a payment of $80 each where the distributor exceeds the interruption duration and or frequency standard. The distributor must also meet specific timeframes in relation to the determination of any such claim and make reasonable efforts to make customers aware of the payments available under this licence condition.

Distributors are required to report quarterly to IPART on their performance against the standards. Their results must be independently audited after the end of each financial year.

See Box B.12 for information on the levels specified in the current standards.

Box B.1 Distribution reliability standards excluded interruptions

For the purpose of reporting against **overall network**, **individual feeder** and **individual customer** reliability standards under a distributor's licence, the following types of interruptions are excluded interruptions:

(a) an interruption of a duration of three minutes or less;

(b) an interruption resulting from:

(i) load shedding due to a shortfall in generation;

(ii) a direction or other instrument issued under the *National Electricity Law*, *Energy and Utilities Administration Act 1987*, the *Essential Services Act 1988* or the *State Emergency and Rescue Management Act 1989* to interrupt the supply of electricity;

(iii) automatic shedding of load under the control of under- frequency relays following the occurrence of a power system under-frequency condition described in the Power System Security and Reliability Standards made under the National Electricity Rules;

(iv) a failure of the shared transmission system;

(c) a planned interruption;

(d) any interruption to the supply of electricity on a Licence Holder's distribution system which commences on a major event day; and

(e) an interruption caused by a customer's electrical installation or failure of that electrical installation.

A major event day is defined statistically to allow major events to be examined separately from daily operation, and in the process, better reveal trends in a daily operation that would be hidden by the large statistical effect of major events.

For the purpose of reporting against **customer service** standards under a distributor's licence, the following types of interruptions are to be excluded:

(a) an interruption resulting from the following external causes:

(i) a shortfall in generation;

(ii) a failure or instability of the shared transmission system;

(iii) a request or direction from an emergency service organisation;

(b) a planned interruption;

(c) an interruption within a region in which a natural disaster has occurred and:

(i) the responsible Minister has made a declaration of a Natural Disaster enabling the NSW Disaster Assistance Arrangements to apply in respect of that natural disaster for that region; and

(ii) the interruption occurred during the period for which a declaration of a Natural Disaster and NSW Disaster Assistance Arrangements were in effect;

(d) an interruption caused by the effects of a severe thunderstorm or severe weather as advised by the Bureau of Meteorology. These effects may include the necessary operation of a circuit protection device which interrupts supply to customers in areas not directly impacted by the severe thunderstorm or severe weather.

Box B.2 Current reliability standards

Copies of the reliability standards are available from IPART's website Licence Conditions and Regulatory Instruments, Available from:

https://www.ipart.nsw.gov.au/Home/Industries/Energy/Energy-Networks-Safety-Reliability-and-Compliance/Electricity-networks/Licence-conditions-and-regulatory-instruments.

Network overall reliability standards

SAIDI standards (minutes per customer)

Feeder Type	Ausgrid	Endeavour Energy	Essential Energy
CBD Sydney	45	N/A	N/A
Urban	80	80	125
Short - rural	300	300	300
Long - rural	700	N/A	700

SAIFI standards (number per customer)

Feeder type	Ausgrid	Endeavour Energy	Essential Energy
CBD Sydney	0.3	N/A	N/A
Urban	1.2	1.2	1.8
Short - rural	3.2	2.8	3.0
Long - rural	6	N/A	4.5

Individual Feeder standards

SAIDI standards (minutes per customer)

Feeder Type	Ausgrid	Endeavour Energy	Essential Energy
CBD Sydney	100	N/A	N/A
Urban	350	350	400
Short - rural	1000	1000	1000
Long - rural	1400	1400	1400

SAIFI standards (number per customer)

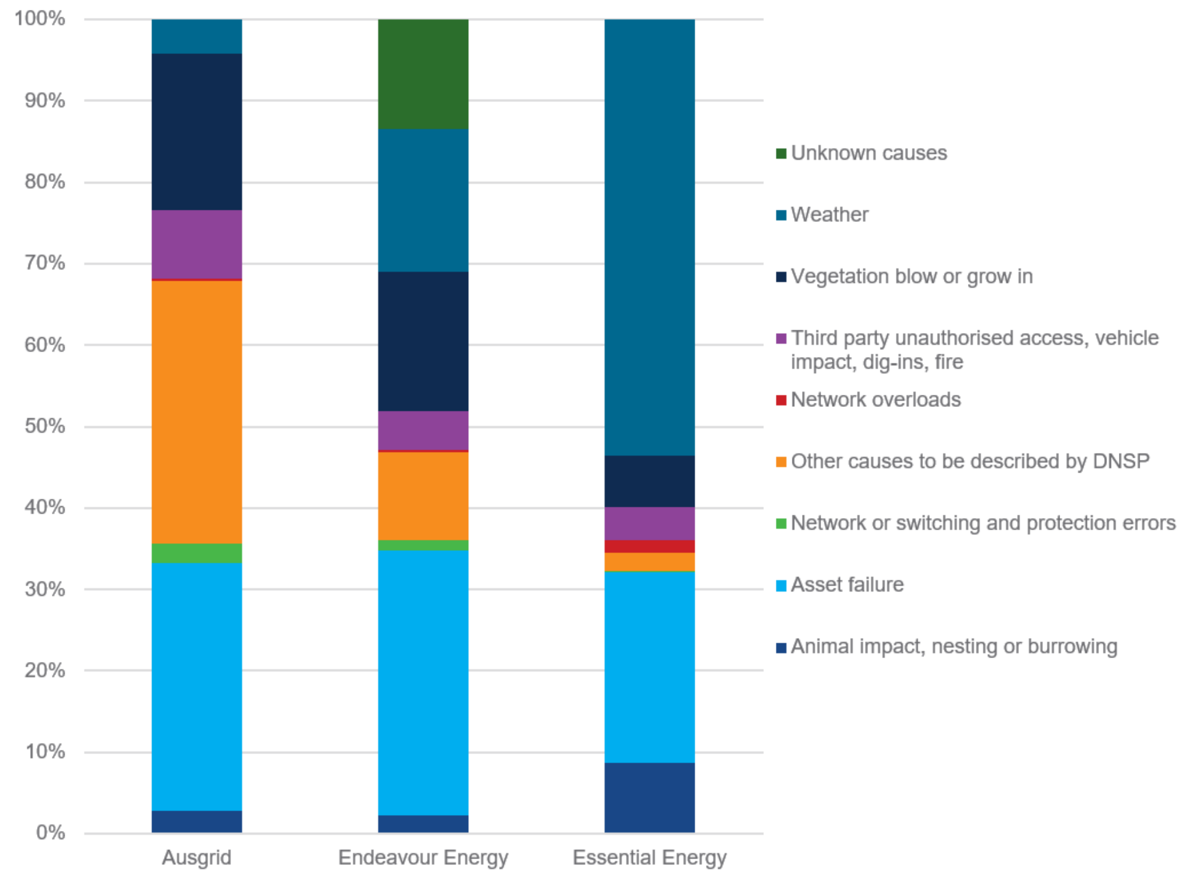
Feeder type	Ausgrid	Endeavour Energy	Essential Energy
CBD Sydney	1.4	N/A	N/A
Urban	4	4	6
Short - rural	8	8	8
Long - rural	10	10	10

Customer service standards (all distributors)

Type of area in which the customer's premises is located	Interruption duration standard (hours)	Interruption frequency standard
Metropolitan	12	4 interruptions of greater than or equal to 4 hours
Non-metropolitan	18	4 interruptions of greater than or equal to 4 hours

Unplanned outages on a distribution network can occur for several reasons. Some factors can be directly influenced by the distributor (eg, equipment failure due to age or condition) while others are outside of the distributor's control (eg, outages on the transmission network or as a result of insufficient wholesale supply). In addition, some factors are a result of extreme events (eg, third-party damage, extreme weather). The most common causes of unplanned outages are asset failure, vegetation and weather (Figure B.22). However these vary by distributor.

Figure B.2 Distributor causes of unplanned outages



Data source: Australian Energy Regulator, 2018-19 Category Analysis RIN responses from Ausgrid, Endeavour Energy and Essential Energy, October 2019, sheet 6.3 Sustained interruptions.

Note: There are differences in the way that each of the distributors classifies Other causes.

The SAIDI and SAIFI levels specified in the current network overall reliability and individual feeder reliability standards have not changed since 2014. Prior to this, the distributors were also required to meet enhanced design planning specifications and reliability standards. These specified security (or redundancy) levels - often referred to as deterministic or N, N-1, N-2 standards – as well as acceptable customer interruption times for different parts of the network.

Deterministic standards specify how much redundancy needs to be built into a network. Standards are expressed using 'N-x' notation, where N refers to the number of elements in a part of the network and x is the number of elements that can fail at the same time without causing an interruption to power supply. For example, a network built to a strict N-1 standard will be able to supply peak load with one element not operating, even if it is the largest element in the network.

Several reviews have identified the pre 2014-deterministic standards as one of the reasons for the high level of investment in NSW distribution networks.[101] For example, in 2018 the ACCC noted that in NSW, Queensland and Tasmania there had been significant over-investment in state-owned networks, driven primarily by excessive reliability standards and a regulatory regime tilted in favour of network owners at the expense of electricity users. It reported that customers in those states continue to pay for over-investment in networks, estimated to amount to $100 to $200 per residential customer per annum.[102]

B.2.2 Distributors' overall network reliability performance is better than the standards

Since 2007-08 the distributors have generally provided higher levels of overall network reliability than is required by their licences.[103]

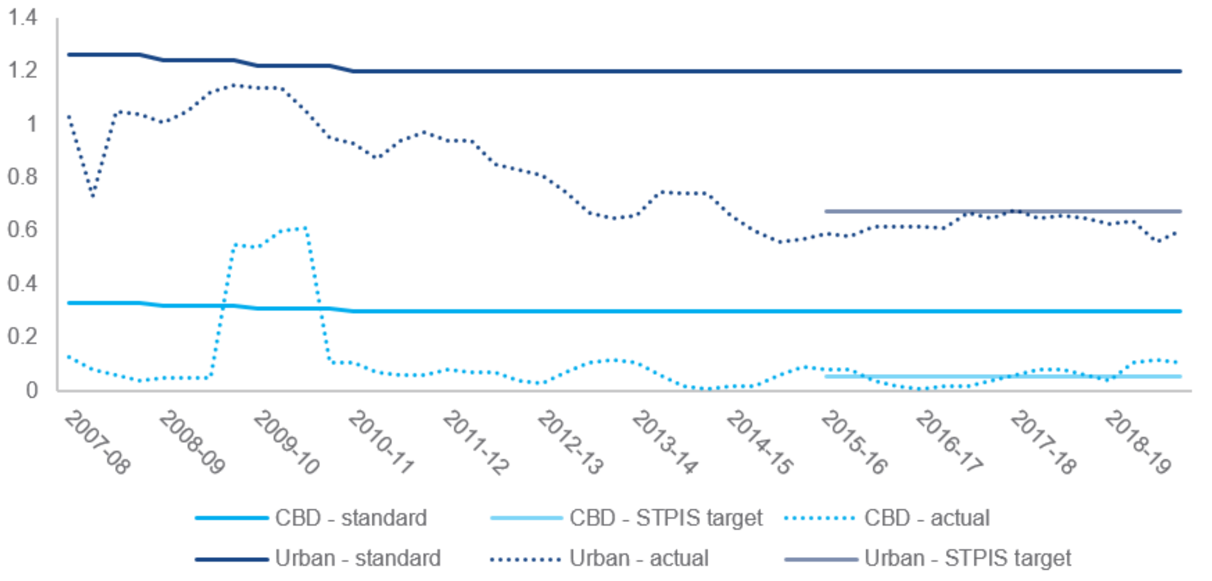
For example, Figure B.3 shows Ausgrid's overall network reliability performance for SAIFI for Sydney CBD and urban feeders. The standard for urban feeders allows for customers on average to experience around one unplanned outage each year (ie, SAIFI of 1.2). Over the last five years, these customers have experienced higher levels of reliability with around one unplanned outage every two years (ie, SAIFI of around 0.6). Since 2015-16 these levels of reliability have been more consistent with the levels set out in the AER's Service Target Performance Incentive Scheme (STPIS) (see section B.3 below for further information).

101 For example see AEMC, Final Report – NSW Workstream Review of Distribution Reliability Outcomes and Standards, p 17, Accessed 21 February 2020, ACCC, Restoring electricity affordability & Australia's competitive advantage, 2018, p 166, Accessed 21 February 2020.

102 Ibid, p ix

103 We note that in some years the distributors have had non-compliances with network overall reliability standards due to minor contraventions related to excluded interruptions.

Figure B.3 Ausgrid – SAIFI performance CBD and urban 2007-08 to 2018-19

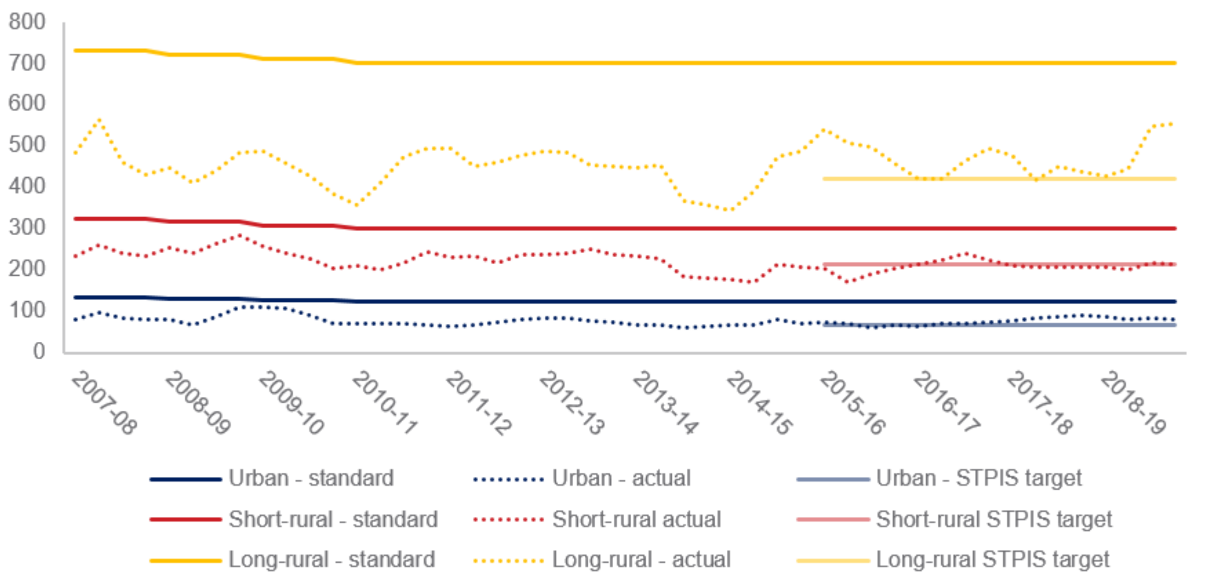


Data source: IPART analysis of information provided by Ausgrid.

Note: Financial incentives for STPIS were introduced from 2015-16.

Similarly, Essential Energy's SAIDI standards allows for long rural feeder customers on average to experience 700 minutes of unplanned outages each year. Over the last five years, these customers have experienced higher levels of reliability with around 400 to 500 minutes of unplanned outages each year.

Figure B.4 Essential Energy SAIDI performance 2007-08 to 2018-19



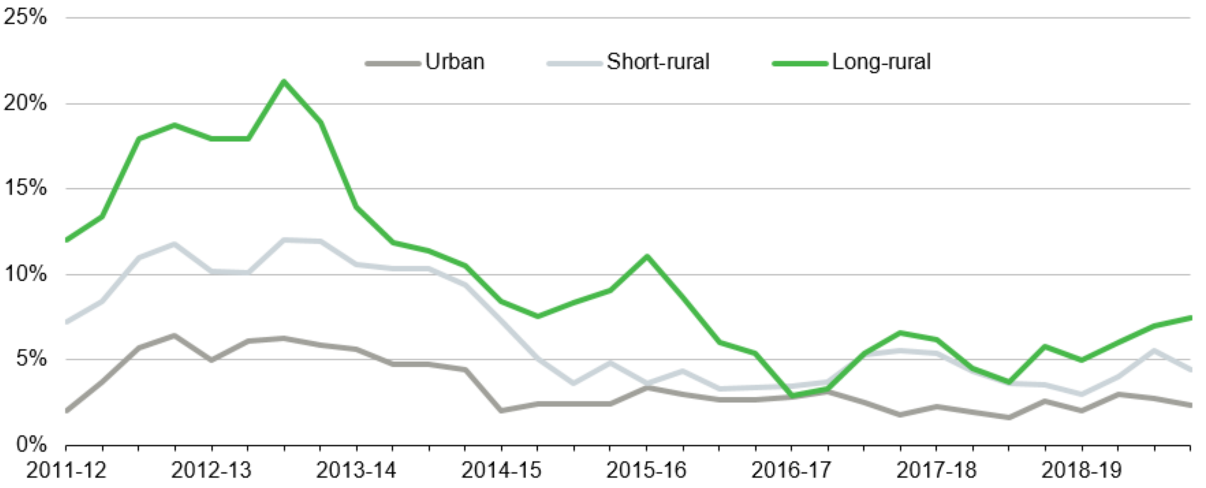
Data source: IPART analysis of information provided by Essential Energy.

Note: Financial incentive for STPIS were introduced from 2015-16.

Each of the distributors have some feeders that do not meet the individual feeder standards. As noted above, the standards require the distributors to report on individual feeders, consider whether it is economically feasible to improve performance on feeders failing to meet reliability standards and report to IPART where they determine that it is not feasible to bring performance up to the required standard. It is not a requirement for every feeder to meet the individual standards.

For example, Figure B.5 shows the proportion of each feeder type for Essential Energy where the levels of SAIDI and SAIFI are above the levels specified in the individual feeder standards. Recently, this percentage has decreased to less than 5% of feeders for urban and short-rural feeders and around 7% for long-rural feeders.

Figure B.5 Essential Energy percentage of feeders above individual feeder standards 2011-12 to 2018-19



Data source: IPART analysis of information provided by Essential Energy

B.3 AER's role in maintaining reliability

Traditionally, distribution services have been considered natural monopolies, and the AER sets the amount of revenue a distributor can collect from its customers and regulates reliability through its incentive framework. However with third-party Standalone Power Systems (SAPS) and distributed generation, distribution network roles are changing.

B.3.1 AER determines the revenue distributors need to meet their standards

The AER determines the total revenue for the distributors, which includes forecasts of operating expenditure and capital expenditure required to meet the standards in their licences. The AER completed its determinations for the 2019-24 period earlier this year.[104]

In their 2019-24 proposals, all three distributors proposed maintaining current levels of reliability.[105] For example, Endeavour Energy's customer engagement found that the majority of customers are not prepared to sacrifice reliability for lower charges, and there is also low appetite to pay more for improved reliability.[106]

B.3.2 The AER also regulates to maintain reliability through STIPS

The NER rule 6.6.2 requires the AER to develop and publish a service target performance incentive scheme (STPIS) to provide incentives to maintain and improve reliability. In developing and implementing STPIS, the NER requires the AER to take into account a range of matters including:

- Consult with the NSW Department administering the NSW electricity jurisdiction
- Ensure the scheme does not put at risk compliance with the relevant service standards in the distributors' licences
- Ensure the benefits to customers are sufficient to warrant a reward or penalty
- Consider the past performance and reliability requirements of the distributor
- Ensure the incentives are sufficient to offset any financial incentives to reduce the costs at the expense of service levels
- Consider customer willingness to pay for improved delivery of services.[107]

The current design of STPIS is intended to balance incentives to reduce expenditure while maintaining or improving service quality, measured by SAIDI, SAIFI and speed at which telephone calls are answered. The distributors receive a reward or penalty based on their performance against targets. The design of the 2019-24 STPIS for all three distributors:

- Sets risk at ±5% of revenue
- Segments the networks based on CBD, urban, short rural and long rural feeder categories using the similar definitions as the licence
- Sets performance targets based on the average performance by each distributor over the past five years (ie, the 2014-19 determination period)
- Excludes specific upstream events from the target in a similar way to the licence conditions.

104 Australian Energy Regulator, *AER decisions deliver efficient costs for NSW electricity distributors*, 30 April 2019 accessed 25 February 2020

105 For example see Ausgrid, Attachment 5.01 – Ausgrid's proposed capital expenditure – April 2018, p 21

106 Endeavour Energy, *Customer and Stakeholder Engagement Activities and Findings – Part A*, p 90, accessed 25 February 2020.

107 NER, Chapter section 6.6.2, Accessed 28 February 2020.

In its 2019-2024 determination, the AER found, based on non-NSW distributors, that STPIS was incentivising greater improvements on SAIFI than SAIDI. As a result, it updated its STPIS to put more weight on SAIDI performance.

The major change in the STPIS for NSW distributors in 2019-24 is the increase in revenue at risk from 2.5% to 5%. Our analysis of reliability over the past suggests that the STPIS at 2.5% was effective at incentivising distributors to maintain reliability at the STPIS level, above licence requirements. For example, as previously shown in Figure B.3 and Figure B.4, distributors' SAIDI and SAIFI performance has been around the levels in STPIS.

Given that STPIS was effective at 2.5%, we expect that doubling the incentives will lead to the distributors prioritising meeting the STPIS targets.

B.3.3 The AER is currently considering the impacts of DER

Distributed Energy Resources (DER) is the collective term for customer-side investment in electricity generation, storage or management. DER encompasses a range of consumer-level technologies used by households and businesses, such as inverter connected generation and storage systems (which at present consist mostly of rooftop solar PV and battery storage systems), energy management systems, controllable loads, and electric vehicles and their charging points.[108]

Electricity consumers are increasingly seeking to generate their own power. People with the ability to generate electricity may still need to source power from the grid or they might choose to sell their excess electricity back to the market.[109]

In systems without DER, voltage is highest at the substation and decreases as the network gets further from the substation. In systems with DER, voltage is increased at every location that is exporting locally generated electricity. This makes it more difficult for the network to manage, as it is difficult to predict how much electricity will be exported at any given time. Failure to maintain power quality (of which voltage is one important part) can also damage the system and lead to supply interruptions.[110]

In the most recent NSW 2019-2024 AER determinations distributors did not propose large expenditures for DER.[111] However, South Australia and Queensland are the two states with the highest penetration of embedded generation (primarily rooftop solar PV systems). Box B.3 below summarises how this has impacted the AER's recent revenue determinations for the distributors in these states.

108 Australian Energy Market Operator, *Technical Integration of Distributed Energy Resources*, April 2019, p 10.

109 AEMC, What is embedded generation? December 2015, Accessed 20 February 2020.

110 Energy Security Board, The Health of the National Electricity Market, 209, p 18, Accessed 27 February 2020.

111 For example, Endeavour Energy proposed to spend $250,000 each year on monitoring solar generation on its feeders and substations. Endeavour Energy, *10.16 Capex Listing (PIP) – Public*, April 2018, accessed 20 February 2020.

Box B.3 The impact of distributed energy resources on the AER's recent price reviews

The AER has reviewed the revised regulatory proposals of the South Australian and Queensland distributors.

The AER did not agree with South Australia Power Networks' (SAPN) original distributed energy proposal capital expenditure on reliability projects. In its revised proposal, SAPN proposed:

- Spending $18.9 million on low voltage transformer monitoring so it can monitor changing loads on the network in real time, and react accordingly.
- Spending $42.2 million on a quality of service program to receive and act on customer inquiries.[a]

In its final decision the AER accepted SAPN's proposed spend relating to its interrelated DER management projects and programs. This included SAPN's low voltage management project that uses new technologies and harnesses data to manage energy flows and optimise generation across the network.

The AER also approved a contingent project so that SAPN can spend money, if directed to, to upgrade the network to maintain reliability, due to the possible impact of DER.[b]

The AER accepted Energex's (the distributor in South East Queensland) proposed augmentations to manage voltage issues related to solar PV. There were no references to solar PV in Ergon Energy's revised proposal.[c]

a SA Power Networks, *Attachment 5 Capital Expenditure, 2020-25 Revised Regulatory Proposal*, December 2019, pp 44-47, accessed 20 February 2020.

b Australian Energy Regulator, *Final decision, SA Power Networks Distribution Determination 2020 to 2025,* June 2020, p 9, accessed 2 October 2020.

c Australian Energy Regulator, *Draft decision, Energex Distribution Determination 2020 to 2025, Attachment 5 Capital Expenditure,* October 2019, pp 22-23, accessed 20 February 2020.

B.3.4 AER reviews the value customers place on reliability

The AER is also responsible for determining the values different customers place on having a reliable electricity supply. This is referred to as the Values of Customer Reliability (VCR). In December 2019, the AER released its Final Report for VCR for unplanned electricity outages of up to 12 hours in duration (i.e. standard outages). These values were calculated in accordance with a methodology which builds upon the Australian Energy Market Operator (AEMO)'s 2014 review of VCR.

VCRs are an important input to help ensure customers pay no more than necessary for safe and reliable energy. VCRs seek to reflect the value different types of customers place on a reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour ($/kWh). Thus, they highlight the competing tensions between reliability and affordability which customers face. VCRs are an important input in identifying efficient levels of network expenditure and in determining the National Electricity Market (NEM) reliability standard and market settings.[112]

112 AER, *Values of Customer Reliability*, p 3, Accessed 21 February 2020.

C Our approach to this review

The purpose of this review is to consider any changes to the electricity distribution reliability standards that could deliver bill savings to NSW electricity customers. In addition, we have been asked to recommend any other measures that could be imposed on the distributors that would be likely to reduce prices and are consistent with the National Electricity Objective.

To make our draft findings and recommendations, we developed an approach that allowed us to take account of the factors we are required to consider for this review as specified in our terms of reference (see Box C.1). This approach involved four key steps:

1. Decide on the role and objectives of the licences, considering the interaction between the licences and other reliability incentives regulated by the AER.
2. Decide on what standards are necessary to meet the licence role and objectives.
3. Decide how to set the necessary standards.
4. Decide on the appropriate licence monitoring and compliance framework.

The sections below discuss each of these steps.

C.1 What are the role and objectives of the licences?

As the first step in our approach, we decided on the role and objectives of the licences in regulating reliability. To do this, we considered how the drivers of reliability have changed over time and the distributors' historical performance against the standards. We also considered the interaction between licence standards and the incentive schemes applying under the AER's regulatory framework. We then assessed two options:

- Mandating an efficient level of reliability in the licences either through overall reliability standards, individual feeder standards or both.
- Creating a requirement to report against a minimum or safety net level of service through the licence, with incentives for efficient levels of reliability being provided through the AER's regulatory framework.

To assist with assessing these options, we engaged HoustonKemp to provide advice on the interaction between the incentives that apply to the distributors under the existing licence standards and the AER's regulatory framework. We also asked HoustonKemp to consider how effectively the AER's framework provides incentives for the distributors to deliver efficient levels of reliability.

Box C.1 Matters we are required to consider as part of the review

In undertaking the review, IPART is to have regard to:

1. the objective of the New South Wales Government to improve electricity affordability while maintaining a reliable and secure network;
2. the potential impact on customer bills, assuming current regulatory arrangements, from:
   a) any change in the distribution network reliability standards;
   b) any other measures that would reduce network prices and are in the long term interests of customers;
3. the value customers place on having a reliable and secure network including the Australian Energy Regulator's (AER) Values of Customer Reliability (VCR) estimates and any other published values;
4. changes that would assist the NSW distribution networks to evolve and take advantage of new technologies that may offer more cost-effective solutions than traditional network investment (such as a stand-alone power systems);
5. the differences in the costs and benefits of delivering reliable network services to different networks and different parts of the network, including CBD, rural, and regional areas;
6. the NSW distribution network businesses' safety and security obligations;
7. a stable regulatory environment;
8. consistency with national incentives and obligations with respect to distribution reliability;
9. the AER's regulatory determinations for the 2019-24 regulatory period;
10. the relevant recommendations of the 2018 State Infrastructure Strategy and the Australian Competition and Consumer Commission's Retail Electricity Price Inquiry and reports which outline the pressures and experiences felt by NSW consumers such as Turning off the Lights: The Cost of Living in NSW by the NSW Council of Social Services and Close to the Edge by PIAC.

C.2 What standards are necessary to meet the licence role and objectives?

In the second step, we decided on what standards are necessary to meet the licences' role and objectives. As a starting point, we compared the role and objectives identified in step 1 to the existing standards. This then allowed us to assess the following:

- Whether any of the existing standards (for example the overall reliability standard) duplicate reliability incentives provided by the AER and so could potentially be removed from the licence.
- Whether changes to existing standards (such as the individual feeder standards and guaranteed service levels and payments) are necessary to better meet the role and objectives of the licences.
- Whether any new standards need to be introduced into the licences to better account for new technologies such as DER and SAPS.

C.3 How should we set the necessary standards?

The third step in our approach was to decide on how to set the necessary standards. This included considering:

- How to set individual feeder and direct connection standards, including how they should be expressed, the types of events to be excluded when measuring performance and the required levels of performance.
- How to set guaranteed service levels and payments for individual customers that experience poor reliability, including the adequacy of the current payments.
- How to provide better incentives for the distributors to efficiently take account of DER and two-way energy flows.
- Whether the licence should set reliability standards for SAPS.

C.3.1 Setting individual feeder and direct connection standards

The main issues we considered when setting individual feeder and direct connection standards were how to express the standards, the types of events to be excluded when measuring performance and the required levels of performance.

To do this, we considered whether the standards should be expressed using measures and exclusions consistent with the national reliability guidelines issued by the AER and assessed whether the SAIDI and SAIFI measures specified in the current standards are consistent with this Guideline. We then applied an economic assessment to these measures to evaluate how efficient network capital and operating costs would vary with different levels of reliability, and compared this level of costs with the value that customers place on reliability.

Our approach used modelling of the long-term efficient levels of SAIDI for three types of feeders - urban, short-rural and long-rural - developed by Nuttall Consulting and in-house. These models estimate both:

- The costs of owning, operating and maintaining feeder assets to achieve a given level of reliability.
- The dollar value of the expected unserved energy to customers at that level of reliability, based on the AER's value of customer reliability (VCR).

We then considered how the level of reliability required by the standards should allow for expected variation from the long-term average efficient levels estimated by the feeder models. To do this, we analysed the relationship between key feeder characteristics, such as length and maximum demand per km, and explored an econometric relationship between these characteristics. We also decided whether standards should vary by location as well as by distributor and whether an econometric relationship was appropriate for all types of feeders (such as feeders greater than 500 km in length).

We then used the results of our modelling to set minimum or safety net levels of reliability for the distributors that are the threshold for triggering a reporting requirement.

We also considered whether our modelling approach should be applied to CBD feeders. These feeders form part of Ausgrid's 'triplex' network, which has been designed to give customers extremely high reliability and is unique to the Sydney CBD.

C.3.2 Setting guaranteed service levels and payments

We considered the role of guaranteed service levels and how to set these levels, having regard to schemes applying in other jurisdictions. We then considered how the licence should treat a failure to meet guaranteed service levels, that is, whether this should constitute a licence breach or trigger a payment to customers (the existing approach).

We have recommended a set of payments to customers for a failure to meet guaranteed service levels. We compared our recommended payments to a number of benchmarks, including the AER's estimate of VCR, the historic value of the existing payments and the level of payments under guaranteed service level schemes in other jurisdictions.

We also considered how the distributors should implement the scheme, that is, whether payments should be made automatically to customers or be available on application by customers (the existing approach). Finally, we considered what information the distributors should be required to publish, so that IPART and the public can monitor how frequently distributors fail to meet guaranteed service levels and how many customers are receiving guaranteed service level payments.

We also considered the role of voluntary compensation schemes. In particular, we considered whether the distributors should report further information on these schemes so that we can better understand:

- How effective they are
- How well they complement guaranteed service levels and payments.

C.3.3 Providing better incentives for DER

We considered the extent to which the licence should account for new technologies, such as DER, and two-way energy flows. While the current reliability standards are designed around one-way flows, the growth in DER increases the potential for two-way flows (as customers with DER export power to the network). This raises the question of whether reliability standards should recognise the value that customers with DER place on the ability to export power to the network.

In particular, we considered the impact of the growing rate of DER on the distributors and their customers, whether the current regulatory framework incentivises efficient DER export expenditure and how the licence could be used to incentivise the distributors to efficiently accommodate two-way energy flows and manage customer exports. To assist us in considering these issues we engaged HoustonKemp to provide advice on an appropriate regulatory framework and associated measures to incorporate the value that customers place on reliably exporting power to distribution networks using DER.

In making our draft recommendations, we had regard to the processes underway at the national level relating to efficiently integrating DER into the energy market and the relevant National Electricity Rule (NER) changes that have recently been submitted to the AEMC.

C.3.4 Setting reliability standards for SAPS

We considered whether the licences should set reliability standards for SAPS. In particular, we considered whether customers of distributor-led SAPS should receive the same protections afforded by the licence as other customers. This is particularly important where a distributor moves (or acquires) a customer from the network to a SAPS without the explicit consent of the customer. We also considered the regulatory framework and arrangements for new connections.

We recognise that amendments to the national and NSW legislative frameworks are required to incorporate distributor-led SAPS into the economic regulation and licensing regimes for distributors. We have made our draft recommendations under the assumption that this will have occurred by 1 July 2024, the date from which we have recommended that our draft licence amendments should apply.

C.4 What is the appropriate monitoring and compliance framework?

The final step in our approach involved establishing the compliance and monitoring framework for the reliability standards, including:

- When any new standards should take effect
- How often distributors should be required to report against the standards (and how these reports should be audited)
- When the standards should be reviewed and who is best placed to conduct future reviews.

D Modelling approach, inputs and assumptions

To inform our recommendations and meet our terms of reference, we estimated the long-term efficient levels of SAIDI for urban, short rural and long rural feeders. The model we used to develop these estimates (the optimisation model) balances:

- The costs of owning, operating and maintaining feeder assets to achieve a given level of reliability, and
- The dollar value of the expected unserved energy to customers at that level of reliability, based on the AER's value of customer reliability (VCR).

This Appendix sets out:

- An overview of the optimisation model and a summary of the key inputs and assumptions we have used in this model.
- The formula we have subsequently applied to set the SAIDI standard for individual urban, short rural and long rural feeders based on feeder length.

D.1 Overview of the optimisation model

D.1.1 Model structure

The model has been developed to investigate the relationship between network supply arrangements and life-time costs, where these costs include:

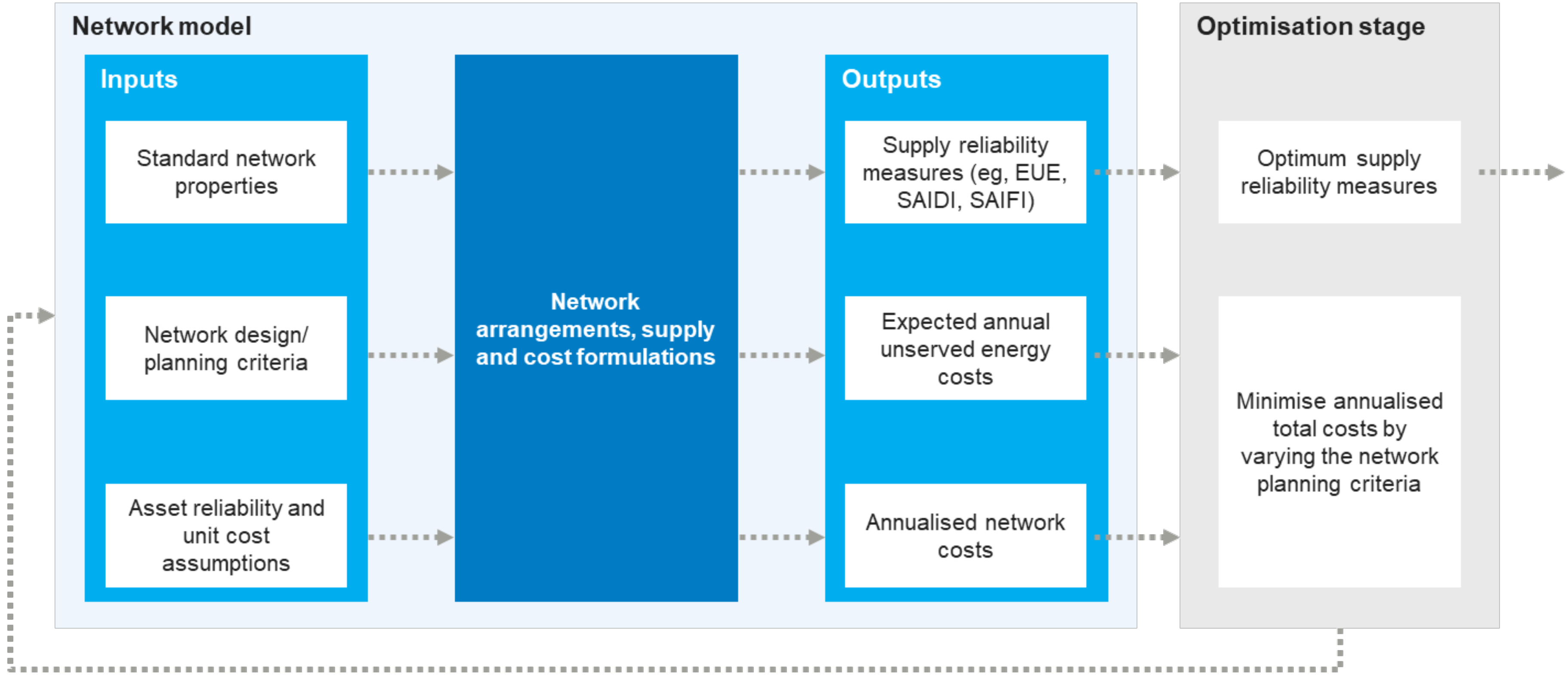
- The capital and operating costs associated with the network supply arrangements
- The economic value associated with the expected reliability of supply provided by the supply arrangements.

In this way, the optimum supply arrangements for elements of the distribution network are determined, based upon the design that minimises these total life-time costs. This in turn is used to provide the expected annual customer supply reliability provided by this optimal design.

The overall structure of the model is shown in the figure below, indicating the following two components of the model:

- Network model: the network model calculates the reliability performance and costs for a specific network arrangement that is defined by a given set of network input assumptions
- Optimisation stage: the optimisation stage finds the optimum network arrangements by varying the sub-set of the input assumptions, which specify design requirements, in order to search for the network arrangements that minimise the total costs (in present value terms).

Figure D.1 Overview of model structure



D.1.2 The network model

We have developed a generic network model of a high-voltage (HV) distribution feeder. A HV distribution feeder represents the electricity lines (either overhead lines and/or underground cables) that emanate from zone substations (ZSS), and typically supplies a large number of customers along its length (eg, a single HV feeder will typically supply 100's to 1000's of customers).[113]

We have focused our model on the distributors' HV feeders (rather than their LV network and/or sub-transmission network) because:

- The performance of this component of the distribution network typically contributes the most to customers' supply reliability
- We consider that this network component represents where variation in the network design and operation will have the greatest effect on the optimised performance of the network.

The generic HV feeder model represents a single feeder. However, the feeder model is defined in a way that it enables us to analyse the typical variations in the arrangements across the distributors and feeder types (eg variations between urban and rural feeders). In this way, the generic model can be 'set-up' to represent an actual feeder through the selection of its input assumptions.

That said, it is important to note that it is not the aim that the model will represent actual arrangements in detail. Instead, it should broadly approximate the network performance and costs we could expect from feeders with similar characteristics.

The generic HV feeder model is shown in Figure D.2 below. It can be viewed as two security zones:

- The first is an N-1 zone, where the feeder supply has some form of backup via connections from adjacent feeders (or other backup capability, including non-network). It is assumed that some portion of any supply interruptions due to a feeder outage in this zone can be restored through this backup capability. Any supply not able to be restored via the backup is assumed to be restored following the repair of the outage.
- The second is a radial N security zone, which is immediately downstream of the N-1 zone. It is assumed that any supply interruptions due to feeder outages in this zone can only be restored following repair of the outage.

113 The HV feeder typically supplies a number of distribution substations (DSS) along its length. The distribution substations then typically supply the distributors' low voltage (LV) network, which is used to provide the supply to individual customers. Depending on their size, some customers could be supplied directly from the DSS, the HV feeder or the sub-transmission system.

Box D.1 The meaning of repair time

Although we discuss here the restoration of all interruptions within the 'repair' time, it does not need to be assumed that this must be the actual time for the full repair of the outage and normal service. This time could include other techniques that typically allow all customer interruptions to be fully restored by the defined model 'repair time', for example through temporary arrangements. This distinction is important in appreciating the feasibility of the repair methods and costs assumptions discussed further below.

The extent of the N-1 zone can be varied such that a fully N-1 type feeder and a fully N type feeder can be defined via the input assumptions. For the feeder model, it is also assumed:

- There is a fault interrupting switch immediately downstream of the N-1 zone (ie, any faults downstream of the N-1 zone will not be interrupted by the substation exit breaker)
- There is some form of switching in the N-1 zone such that a faulted feeder section in this zone can be isolated in order that all customers in this section can be restored provided there is sufficient backup capability.

The N zone is defined by:

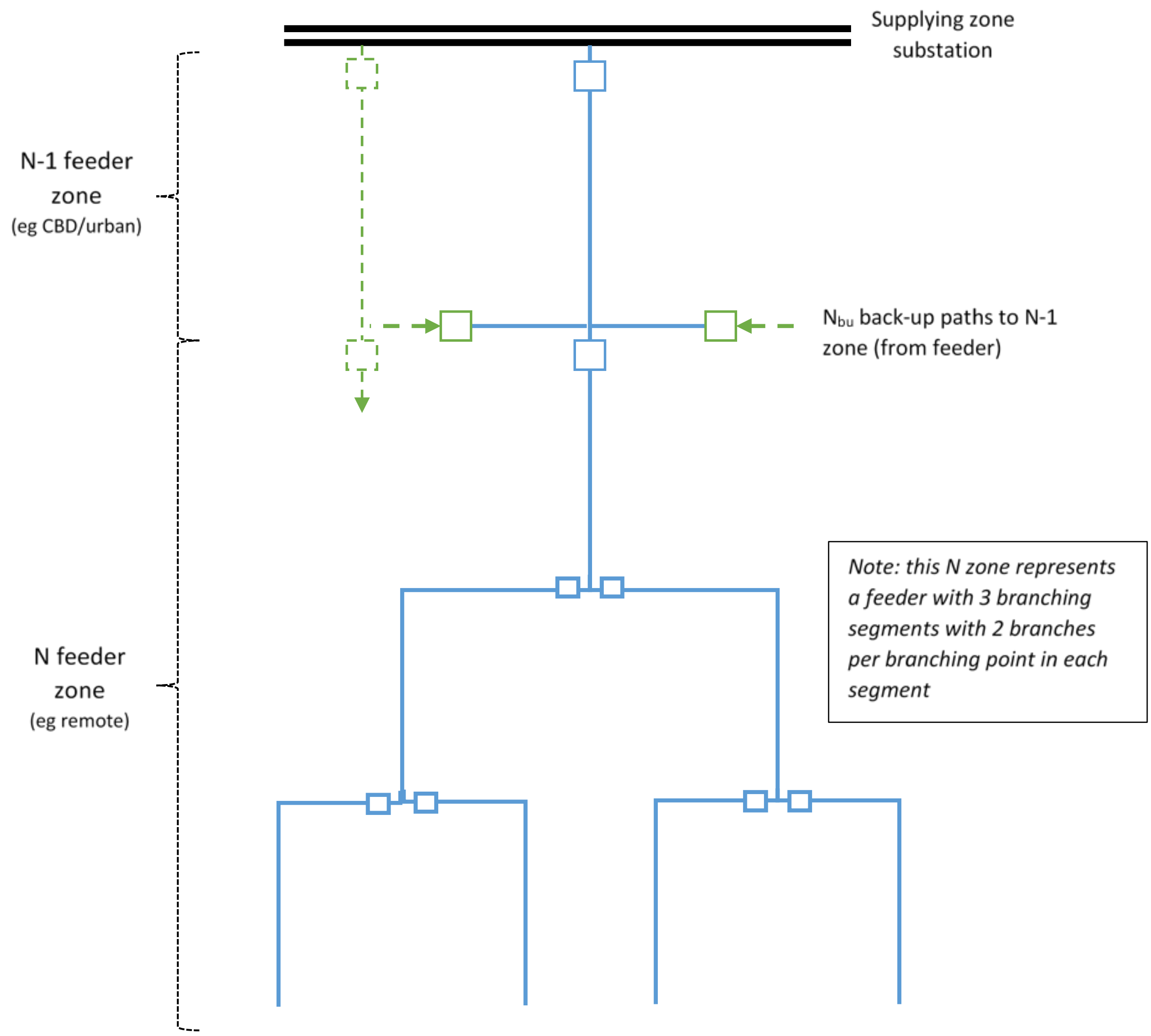
- The number of 'branching' segments along this zone (these are assumed to be equally spaced in the model)
- The amount of 'branching' that occurs at each branching point in the segment (the amount of branching is assumed to be same at each branching point in the model).

For example, in Figure D.2 there are three branching segments in the N zone and the amount of branching is two.

The model distributes the customer load in terms of maximum demand (ie, MW), energy (ie, MWhr) and customer numbers along the length of the feeder. However, alternative loading patterns can be selected. These alternatives cover:

- Uniform distribution, where the proportion of the load is constant along the length of the feeder
- Inverse power law distributions, where the proportion of load reducing from the feeder exist is inversely proportional to the distance along the feeder, where distance is raised to a defined power (ie, 1/distance, 1/distance^2, or 1/distance$^{1/2}$).

Figure D.2 Feeder model supply arrangements



D.1.3 Overview of model inputs

The specific network arrangements are set via the model inputs. These inputs can be considered as three types, which reflect how they are used for defining specific feeder arrangements, namely:

- Feeder properties
- Feeder design and planning criteria
- Asset reliability and unit cost assumptions.

Feeder properties

The feeder properties define the various characteristics of a specific the feeder being modelled, which we consider will be fixed for the optimisation process. These properties cover:

- Feeder load information, including:
  - The feeder category (ie, urban, short rural, etc)
  - The maximum demand, annual energy supplied, load duration curve and load factor
  - The customer numbers
  - The load distribution model form
  - Value of customer reliability (VCR defined as $ per MWhr unsupplied)
  - Feeder diversity/coincidence factor
- Feeder physical information, including:
  - Feeder length
  - The proportion overhead and underground.

Network design and planning criteria

The network design and planning criteria define the various design and operating requirements of the feeder being modelled. These represent the criteria which we consider could be varied through the optimisation process – although for optimisation only a subset have been varied (this is discussed below).

The criteria are defined in a way that broadly reflects a classical deterministic planning approach. However it is important to note that the model uses a 'probabilistic' planning approach (ie, a formal quantitative risk-based cost-benefit analysis method) to optimise these criteria.

The criteria for each feeder cover:

- N-1 zone portion: the portion of feeder that must be secured via the N-1 requirements (ie, the portion of the feeder in the N-1 zone as percentage of its length)
- Load at risk: the portion of the maximum demand, which is at risk of being interrupted should an outage occur in the N-1 zone, after allowing for the available backup capability but before repair of the outage

- The number of back-up paths in the N-1 zone (ie, how many adjacent feeders will provide the backup capability)
- Restoration time: the time to restore the network to the relevant load at risk criteria using the back-up capability, which imposes design requirements on switching arrangements to make use of the defined back-up supply capability
- Repair time: the time to fully restore supply to the normal service levels, which typically imposes requirements on the management of spares, asset procurement and repair and replacement protocols
- The number of branching segments and amount of branching in the N zone.

Asset reliability and unit cost assumptions

The asset reliability and unit cost assumptions are the underlying assumptions that we use, via the network formulations within the model, to calculate the output network costs and supply reliability for a given set of feeder properties and planning criteria inputs.

These assumptions define the various fixed data tables and other assumptions, which the optimisation process uses to calculate the outputs.

These assumptions cover:

- Cost functions and assumptions:
  - Feeder capital cost functions (ie, cost per length and per rating)
  - Restoration cost function (ie, capital and operating cost as a function of restoration time)
  - Repair cost function (ie, capital and operating costs as a function of repair time)
  - Maintenance cost rates (ie, average annual maintenance as a percentage of capital cost)
  - Asset lives
- Existing feeder reliability assumptions:
  - Feeder outage rate (ie, unplanned outages per unit length per year)
  - Average customer interruption duration due to an unplanned feeder outage
  - Average proportion of feeder customers interrupted per unplanned feeder outage.

D.1.4 Overview of model outputs

The network model calculates various outputs for a given set of inputs. The key outputs can be considered as two types:

- Various supply reliability measures, which are used to define the resulting reliability standards
- Supply costs, which include the costs of constructing and operating the network and the economic cost of the supply reliability (which are required by the model's optimisation process).

Supply reliability measures

The model calculates various measures of the long-term average (ie, expected) reliability performance of the feeder arrangements. These measures cover:

- Expected unserved energy (EUE). EUE is the key metric being costed by the model using the VCR input. As noted above, the calculation of EUE in the model uses a similar methodology (often referred to probabilistic planning) to that often used in the distribution industry for applying formal cost-benefit analysis to network investment planning and decision-making.
- SAIDI, SAIFI and CAIDI, as follows:
  - SAIDI measure estimated from the EUE value using an average energy per customer minute conversion rate. This is used to convert the EUE to a value of customer minutes interrupted (CMI), which is then used to calculate SAIDI (where SAIDI = CMI / total customers). This method should reflect the usual method used in the industry to covert an EUE measure to the reported reliability measure.
  - SAIFI is calculated within the model by calculating customer interruption numbers from:
    - i) The various inputs that define where the protection devices must be located along the feeder
    - ii) The customers calculated to be downstream of these devices (ie, the customers who will be interrupted if that device opens)
    - iii) The number of outages that would be isolated by that operation of that device.
  - CAIDI is calculated as SAIDI divided by SAIFI, in line with the standard formula.

Supply costs

The model calculates the following two costs:

- Annualised network cost, which is calculated as the annualised capital cost plus average operating costs of the network arrangements
- Expected annual reliability cost, which is calculated as the EUE measure multiplied by an assumed value of customer reliability (VCR).

It is worth noting that the total annualised cost is used for optimisation purposes (where total annualised costs = annualised network costs plus expected annual reliability cost). The expected annual reliability cost and network operating costs are inherently calculated on this basis. Capital costs are transformed to this basis using an assumed asset life and discount rate, based on the following formula of the equivalent annual cost:

$$\text{Annualised capital cost} = d \,.\, \text{capital cost} \,/\, [(1-(1+d)^{-\text{Life}}) \,.\, (1+d)];$$

where d = discount rate.

D.1.5 Model network formulations

The network formulations calculate the various outputs, for the given set of inputs.

These formulations start by calculating various internal network parameters, including the network capacity, back-up capacity, the switching and restoration form, and the repair method. These parameters specify the network arrangements that are required to meet the given planning criteria for the given network properties.

For example, the required capacity of the feeder and the required back-up capacity can be calculated, given the supplied maximum demand, the load-at-risk and the number of back-up paths.

These calculated internal network parameters are then used to calculate the output supply reliability measures, using the assumed asset failure frequencies, load durations curves and other network property assumptions. These calculations use typical formulations used for probabilistic planning of distribution networks, which rely on estimating the expected unserved energy from load durations curves, using network load limits (which are defined by the calculated capacity requirements) and asset unavailability probabilities (which are defined by the failure frequencies, and restoration and repair times).

Together, the calculated internal network parameters and reliability measures are then used to calculate the two key cost outputs, based on the various unit cost assumptions.

D.1.6 Overview of model optimisation process

The optimisation stage adjusts the planning criteria inputs to determine the set that produces the minimum total annualised system cost. This ‘optimum’ input set will then define the economically optimum supply reliability measures for that feeder.

In this way, the optimum network arrangements can be understood both in terms of their specification as input design criteria and output supply reliability measures. Although output-based measures (eg, SAIDI, SAIFI) will be used to define the reliability standard, the visibility of the equivalent input design criteria is useful in understanding the optimum results and the relevance of these on the network arrangements.

The specific planning criteria that we have varied through the optimisation process and the others we have assumed to be fixed are explained below.

D.2 Model inputs and assumptions

The following sections provide a comprehensive summary of the key inputs and assumptions we have applied for each distributor, including the basis of our derivation of these inputs and assumptions.

D.2.1 Existing reliability assumptions

As noted above, the model used the following three inputs to define the existing feeder reliability:

- Feeder outage rate (ie, unplanned outages per unit length per year)
- Average customer interruption duration due to an unplanned feeder outage
- Average proportion of feeder customers interrupted per unplanned feeder outage.

The functions that define these inputs for each distributor have been derived from the interruption data reported by the distributor in their Category Analysis Regulatory Information Notices (RIN).

The following tables summarise the three functions we have used for each distributor.

Table D.1 Feeder outage rate

Distributor	Feeder outage rate function
Endeavour	Feeder outages (for feeders >= 10% overhead length) = 0.126 + 0.0927 x feeder length (km) Or Feeder outages (for feeders < 10% overhead length) = 0.135 + 0.0115 x feeder length (km)
Essential	Feeder outages (for feeders >= 10% overhead length) = 0.0744 x feeder length (km) Or Feeder outages (for feeders < 10% overhead length) = 0.018
Ausgrid	Feeder outages (for feeders >= 10% overhead length) = -0.2 + 0.084 x feeder length (km) Or Feeder outages (for feeders < 10% overhead length) = 0.21
Limit assumptions	The model limits the outage rate given by these function to be no lower than 0.0001.

Table D.2 Average customer interruption duration

Distributor	Average customer interruption duration function
Endeavour	92.51 minutes for feeder length >0km and <= 10km 116.56 minutes for feeder length >10km and <= 20km 161.09 minutes for feeder length >20km and <= 50km 209 minutes for feeder length >50km
Essential	102.4 minutes for feeder length >0km and <= 10km 113.3 minutes for feeder length >10km and <= 20km 150.0 minutes for feeder length >20km and <= 40km 187.0 minutes for feeder length >40km and <= 200km 230.7 minutes for feeder length >200km and <= 1000km 320.8 minutes for feeder length >100km
Ausgrid	141.35 minutes for feeder length >0km and <= 20km 196.84 minutes for feeder length >20km and <= 50km 213.81 minutes for feeder length >50km and <= 160km 262 minutes for feeder length >160km

Table D.3 Average proportion of customers interrupted

Distributor	Average proportion of feeder customers interrupted function
Endeavour	Feeder customer proportion = 1.09 – 0.19 x $\log_e$ (feeder length (km))
Essential	Feeder customer proportion = 0.9 – 0.135 x $\log_e$ (feeder length (km))
Ausgrid	Feeder customer proportion = 1.09 – 0.19 x $\log_e$ (feeder length (km))
Limit assumptions	The model limits the proportion given by these function to be between 9% and 99%.

D.2.2 Model cost assumptions

Feeder capital cost model

Purpose: Estimate of the capitalised cost of a modelled feeder.

Coverage of costs: All direct constructions, installation and commissioning costs of the HV feeder, including overhead conductor, overhead structures, underground cable. Excludes:

- Switches associated with fault interruption and restoration (see calculations below)
- All DSS and LV network components (these are not covered by the feeder model).

Formulations: the cost of a feeder is estimated as a function of its length, rating, overhead/underground proportion, and load type, using the following formulas:

- feeder base cost = feeder length (km) . c . feeder rating (MVA) ^ b (ie, power law)
- feeder cost = network type multiplier . feeder base cost

where:

- feeder length (km) is the total length of the feeder, or feeder segment being costed
- feeder rating (MVA) is the thermal rating of the feeder, or feeder segment being costed
- c and b are fixed parameters of the cost model that define the power law relationship (see below for basis)
- network type multiplier is used to scale the feeder base costs to reflect the properties of a specific feeder, including
  - proportion of overhead vs underground
  - whether CBD, Urban, Short Rural, Long Rural.

Basis of cost model parameters:

We have used the 2018-19 RIN data of each distributor as the basis for estimating the parameters of its feeder cost model, as follows:

- Average feeder unit costs (cost per km) have been calculated based on an estimate of the total replacement cost of all feeders and total length of all feeders.
- The total feeder replacement cost has been estimated separately for the overhead network and underground network using the relevant age profiles (ie, asset quantities) in the 2018-19 Category Analysis RIN (template 2.5) and the AER benchmark unit costs it derived through its repex modelling exercise
- The total overhead and underground feeder length has been calculated from the feeder table in the 2018-19 Annual Reporting RIN
- To apportion total feeder costs to the urban and rural feeder types, we have assumed relative differences in the unit costs between categories as follows:
  - CBD is 200% of Urban
  - Short Rural is 70% of Urban
  - Long Rural is 90% of Short Rural
- We have assumed the b parameter of the power law to be 0.33 (ie, the cost per unit length increase is the cubed root of the feeder rating)
- The c parameter of the feeder base cost power law has been set using the typical feeder ratings for the feeder types (as reported by the distributors in the Augex Model tables in their most recent Reset RIN) such that the average feeder unit cost provided by the power law for this rating matches the average feeder unit cost calculated from the RIN data.

Feeder cost model parameters:

The tables below summarise the parameters of the three cost models developed for each distributors.

Table D.4 Power law parameters

Distributor	Power law c . MVA ^ b ($millions per km	
	b parameter	c parameter
Endeavour	0.333	0.1671
Essential	0.333	0.1005
Ausgrid	0.333	0.1645

Table D.5 Overhead multipliers

Distributor	CBD	Urban	Short Rural	Long Rural
Endeavour	na	1.00	0.71	0.73
Essential	na	1.00	0.82	0.71
Ausgrid	2.06	1.00	0.73	0.76

Table D.6 Underground multipliers

Distributor	CBD	Urban	Short Rural	Long Rural
Endeavour	na	2.18	1.55	1.58
Essential	na	3.92	3.20	2.76
Ausgrid	3.78	1.84	1.34	1.40

Restoration cost model

Purpose: Estimate of the cost of the assets (eg, switches and associated control/communication) required to restore customer supply following an outage in the N-1 security zone and the costs of performing the restoration (per outage event) for a given restoration time.

Note that this reflects the costs necessary to restore customer supply via methods such as switching and load transfers (prior to the repair of the outage). As such, these costs are only relevant to the N-1 security zone.

Coverage of costs:

Capitalised costs covering all direct design, construction, installation and commissioning of the asset equipment, facilities necessary to perform the restorative network switching following outages on the modelled feeder. This allows for the feeder level switching and any associated communications, control and SCADA costs necessary to achieve different switching methods, covering manual/field switching, remote or automatic switching.

Operating costs covering all direct operating costs associated with performing the restoration, following an outage event (ie, unit operating costs per outage). This would include the costs of field activities necessary to perform manual switching and any office/control room activities to plan and manage the restoration.

Note that it is recognised that actual operating costs will vary depending on the specific circumstances of any outage and the customers interrupted. The unit operating costs used in the model should approximate the average unit cost for the modelled feeder.

Formulations:

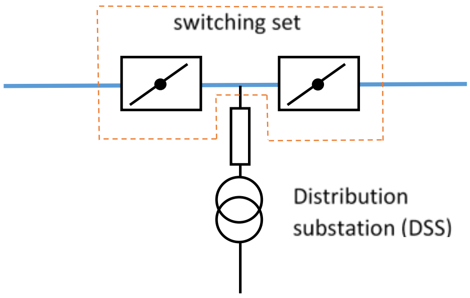
The formulations for calculating the capital and operating costs are based upon two unit-cost functions, which define the capital and operating unit cost as a function of the restoration time.

The two unit-cost functions are defined by fitting a curve based upon the estimated costs and restoration times for three restorative switching methods and assumed times:

- Fully manual: assuming the restoration will occur in 180 minutes
- Fully remote: assuming the restoration will occur in 30 minutes
- Fully (fast) automatic: assuming the restoration will occur in 1 minute.

The capital unit-cost function defines the capital cost per switching set. The model assumes that all load in the N-1 zone can be restored, provided there is sufficient backup capacity. Consequently, a switching set allows for two 3-phase switches, in order that, following a fault on the HV feeder, supply to any distribution substation (DSS) and associated downstream LV network can be restored via switching, while still allowing for the isolation of the faulted feeder section, as shown in the figure below.

Figure D.3 N-1 zone restoration switching set example diagram



The number of switching sets for the modelled feeder are estimated based upon another function (switching sets function). The switching sets function defines a relationship between the number of switching sets in the N-1 zone and the customer demand, customer numbers and length of feeder in this zone. In this regard, this function reduces the number of switching sets as customer density increases. This function can be considered to represent the effect of the change in the typical DSS size (in kVA terms) in the N-1 zone as customer density increases, whereby we would expect the average DSS size to increase as the density increased.

The switching sets function is constructed as follows:

- Number of switching sets = maximum demand in N-1 zone / (average DSS size x 60%)
- Where the average DSS size = L1 x L2, where both L1 and L2 are linear functions, as follows:
  - L1 can be viewed as a base DSS size, which increases linearly from 75kVA to 350kVA as the customers per km (in the N-1 zone) increases from 20 to 100 – the function is 'clipped' between these bounds
  - L2 can be viewed as a scaling of the base DSS, which increases linearly from 1 to 5 as the maximum demand per customer (in the N-1 zone) increases from 2 kVA to 100 kVA – the function is 'clipped' between these bound
- And the 60% is an assumed typical DSS utilisation factor
- In addition, the number of switching sets must be no greater than the number of customers.

In this way, number of switching sets calculated by the switching sets function is then input to the capital cost function, along with the restoration time, to calculate the capital cost of the assets to achieve this restoration time.

The operating unit-cost function defines the operating cost per outage events (affecting the N-1 zone). The number of outage events are calculated by the model, based on the network arrangements and feeder outage rates.

Restoration cost assumptions:

The feeder restoration capital unit costs are shown in the table below.

Table D.7 Feeder restoration capital unit costs ($s)

Switching method	Restoration time	Capital unit cost (per switch set)	Cost basis
Manual	180 minutes	$5,000	The manual switch cost allows for a simple switch/disconnector, without any remote monitoring or control facilities. We have assumed a unit cost of $12,000 per pole mounted switch to produce a total switching set cost of $24,000. However, this total cost is reduced by $19,000 to allow for the poles, fittings and disconnectors that are necessary irrespective of whether the DSS is in the N-1 or N zone.
Remote	30 minutes	$141,000	The remote switch allows for a switch type and associated facilities that can be remotely monitored and controlled from the network control room, where the costs include any necessary measuring/monitoring, communication and control, at both the feeder-level and control room to facilitate a remote restoration methodology. We have assumed a unit cost of $80,000 per pole mounted switch to produce a total switching set cost of $160,000. However, similar to the manual switch, this total cost is reduced by $19,000 to allow for the poles, fittings and disconnectors that are necessary irrespective of whether the DSS is in the N-1 or N zone.

Switching method	Restoration time	Capital unit cost (per switch set)	Cost basis
Fast automatic	1 minute	$191,000	The automatic switch allows for a switch type and associated facilities that can be remotely monitored and controlled from the network control room, but also has the appropriate dedicated monitoring and control system to automatically switch and restore supply, where the costs will include those of the remote switch type and any additional costs to allow for an extensive automated feeder restoration scheme for the N-1 zone, including design, testing and commissioning and associated dedicated communication/control hardware and software. We have assumed a unit cost for the switch installation will be similar to the remote switch, as this will require similar hardware. This estimate assumes any necessary ADMS and SCADA system is in place. However, we have assumed an additional $50,000 per switching set to allow for the automation design, testing, and commissioning, including any software/system upgrades.

In addition, an uplift of 20% is applied to these costs to reflect the increase in costs we expect when ground mounted / kiosk switching associated with predominantly underground feeders is necessary. This uplift on costs is applied when less than 30% of the feeder by length has been reported by the distributor to be overhead construction.

The feeder restoration operating unit costs (per outage event) are shown in the table below.

Table D.8 Feeder restoration operating unit costs ($s)

Switching method	Restoration time	Operating unit cost (per switch set)	Cost basis
Manual	180 minutes	$1,800	The manual operating costs assume on average 18 hours of labour, allowing for direct field, control room and other office activities, with an average direct labour rate of $100 per hour.
Remote	30 minutes	$600	The remote operating costs assume on average 6 hours of labour, allowing for direct control room and other office activities, with an average direct labour rate of $100 per hour.
Fast automatic	1 minute	$300	The automatic operating costs assume on average 3 hours of labour, allowing for direct control room and other office activities, with an average direct labour rate of $100 per hour.

Outage repair cost model

Purpose: Estimate of the cost of the assets, equipment and field activities required to repair the network (per outage event) for a given repair time (where 'repair time' is the time from the commencement of the outage to all supply interruptions being restored).

Note that it is recognised that actual repair costs will vary depending on the specific circumstances of any outage. The unit costs used in the model should approximate the average repair cost for the modelled feeder and given repair time.

Furthermore, as discussed above, although we label these 'repair' costs here, these costs could include techniques that allow customer supplies to be fully restored by the defined 'repair time' through temporary arrangements, while the actual repair is being performed (eg, temporary line bypass arrangements or temporary alternative supply/generation). This distinction is important in appreciating the feasibility of the 'fast' repair methods and costs discussed below.

Coverage of costs:

The cost model covers two components:

- Asset costs: the direct costs associated with the assets, equipment, facilities necessary to perform the repairs and restorations for the given repair time. This should allow for any specialised assets and equipment necessary to perform faster repairs and/or restoration than usual. It is assumed that the use of these assets, equipment and facilities will be spread across the network, and will not be specific to the feeder being modelled. Therefore, these costs are treated as a type of service cost in the model, rather than a capitalised cost.
- Operating costs: the operating costs directly associated with any specific repair for the given repair time. This would include the costs of the field activities necessary to perform the repair/restoration and any office activities to plan and manage the repair.

Formulations:

The formulations for calculating the two cost components are based upon two cost functions, which define the unit costs (cost per repair event) as a function of the repair time.

The two unit-cost functions are defined by fitting a quadratic curve based upon the assumed costs and repair times for the following three repair methods:

- Very fast repair: assumes an average repair time of 4 hours and requires specialist assets, equipment and facilities to enable this rapid repair time, and enhanced operating/field activities
- Fast repair: assumes an average repair time of 6 hours and requires specialist assets, equipment and facilities to enable this fast repair time, and enhanced operating/field activities
- Normal repair: assumes a repair time of 8 hours with no specialist assets or equipment and usual operating/field activities.

Repair cost assumptions:

The asset investment capital costs necessary to significantly reduce repair times could cover a broad range of options, including:

- Increased emergency spares
- Temporary line arrangements
- Mobile generation and mobile substations
- Non-network support services
- Increased/enhanced fault location detection devices and/or systems.

The best solution would likely include a range of these options and others. The best make-up of these options, including the quantities and depot locations necessary to reduce average repair times, will be specific to the distributor.

We have assumed an indicative aggregate cost, which we consider is a reasonable amount to purchase a selection of the above options (or others) that could be used to reduce average repair times in the order suggested.

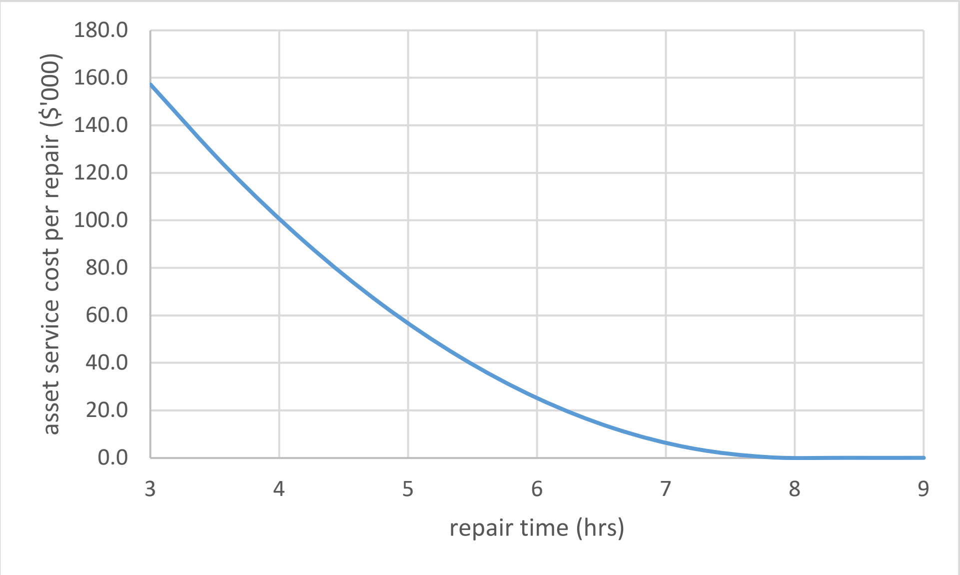
The repair capital unit cost assumptions used in the model and the associated cost function are shown in the table and figure below.

Table D.9 Repair capital unit cost assumptions

Repair method	Repair time	Asset investment	Service cost (per repair event)[a]
Very fast	4 hours	$200 million	$100,600
Fast	6 hours	$50 million	$25,100
Normal	8 hours	-	-

a This assumes the specialist assets have a 15 year life, the service provides 5% return, and assets have a 50% utilisation.

Figure D.4 Cost function for repair capital unit-cost



Similarly, the operating unit costs for enhanced repair methods could cover a range of factors, including:

- Increased response and repair crew sizes
- Specialist and more costly skill sets
- Increased control room and/or depot staff levels.

For similar reasons to those discussed above on our capital costs assumptions, we have not attempted to develop a bottom-up estimate of operating unit costs. Instead, we have assumed an indicative aggregate cost which we consider is a reasonable amount to allow for a selection of the above options (or others) that could be used to reduce average repair times.

However, the normal operating cost assumption has been set to broadly align with the average emergency response cost we could estimate from the emergency response operating costs that the distributors have reported in their 2018-19 Category Analysis RIN. The relative difference in the normal repair cost has then been used to scale the costs for the two enhanced repair methods. Note, with regard to this scaling, we are assuming that these differences are due largely to uncontrollable factors affecting these costs, and so do not reflect any inherent inefficiency between distributors.

The repair operating unit cost assumptions used in the model are shown in the table below.

Table D.10 Operating unit cost (per repair, $'000)

Repair method	Repair time	Endeavour	Essential	Ausgrid
Very fast	4 hours	60	60	120
Fast	6 hours	30	30	60
Normal	8 hours	15	15	30

Maintenance cost rate

Purpose: Estimate of the maintenance costs of the feeder assets.

Coverage of costs: The direct costs of the maintenance of the assets that form the feeder or directly affect the service of the feeder. This would include the costs of the field activities necessary to perform the maintenance and any office activities to plan and manage the maintenance activities.

Formulations:

The maintenance costs are estimated using constant maintenance cost rates that define the average annual maintenance costs as a proportion of the feeder capital costs. In this way, the annual feeder maintenance cost = maintenance cost rate x feeder capital cost.

Two maintenance cost rates have been calculated, covering the overhead network and the underground network (noting we would expect these to have significantly different maintenance rates).

Maintenance rate assumptions:

We have derived the rates from the maintenance costs reported in the 2018-19 Category Analysis RINs (templates 2.1.2 and 2.8.2) and total network replacement costs we estimated to calculate the feeder unit capital costs discussed above.

The maintenance cost rates we have calculated for each distributor are shown in the table below.

Table D.11 Maintenance rates (as % of capital cost)

Distributor	Overhead	Underground
Endeavour	1.75%	0.36%
Essential	1.02%	0.35%
Ausgrid	1.67%	0.34%

D.2.3 Other model assumptions

Individual feeder properties

The feeder properties for each individual feeder being modelled have been taken from the following sources:

- Feeder total length (km), the proportion overhead (%), the maximum demand (MVA), customer numbers and the current feeder category (ie, urban, short rural, etc) have been taken directly from the 2018-19 Annual RIN of the relevant distributor.
- The feeder load duration curve and load factor have been assumed to be equivalent to the supplying zone substation. We have calculated the supplying zone substation load duration curve and load factor from substation load profiles published by the distributors.
- The total customer energy supplied by the feeder is calculated, based upon the feeder maximum demand and the assumed load factor, discussed above.
- Estimates of feeder-specific VCR were provided by Endeavour and Essential. Ausgrid has not yet provided these estimates so we developed our own estimate of VCRs for each feeder on the Ausgrid network and have used these in developing our draft recommendations.

Design and planning criteria

We have varied the following four planning criteria through the optimisation process:

- Portion of feeder (by length) in N-1 zone
- Load at risk (of outage in N-1 zone)
- Restoration time
- Repair time.

The number of back-up paths in the N-1 zone is assumed to be 2 for all feeders as this reflects the typical number of adjacent feeders it could be expected will provide back-up capability to a feeder. The number of 'branching' segments in the N zone and the amount of 'branching' at each branching point in the segment has been set based upon the assumptions in the table below.

These branching assumptions were estimated from actual distributor interruption data (Ausgrid) by estimating the parameters for feeders in the defined length ranges, where the distribution of the proportion of customers interrupted by each outage given by the model best represented the actual distribution we calculated from the actual data. A length relationship was used as we considered it reasonable to assume that length was the most significant factor, in general, influencing the extent of branching in the N zone (ie, we would expect that as the length of a feeder increased there would tend to be a greater number of branching points and branches in the feeder).

Table D.12 Branching assumptions

Length range		Overhead		Underground	
lower	upper	segments	branches	segments	branches
0	5	1	1	1	1
5	10	1	2	1	1
10	15	1	2	1	2
15	20	1	2	1	2
20	30	2	2	2	2
30	40	3	2	3	2
40	60	3	2	3	2
60	80	3	2	3	2
80	120	2	3	2	3
120	150	2	4	2	4
150	200	3	3	3	3
200	500	3	3	3	3
500	3000	4	4	4	4

Other general assumptions

The table below summarises the other assumptions that we have applied in the model.

Table D.13 Other modelling assumptions

Model parameter	Value
Feeder coincidence factor	95%
Feeder N-1 zone backfeed portion[a]	30%
Discount rate	3.0%

a This represent the amount of additional feeder that is constructed to provide the backfeed capability.

D.3 Derivation of formulae for SAIDI and SAIFI single-feeder standards

The proposed new standards are based on formulae for the upper limits on SAIDI and SAIFI for an individual feeder in any year. Whenever a feeder exceeds either of these limits in a reporting year, the distributor would need to notify IPART and participate in an investigation of the reasons for that non-compliance.

The formulae express the upper limits as a function of feeder length. We determined that feeder length[114] is the most important determinant of SAIDI and SAIFI performance through statistical analysis of past interruption data. The formulae are:

$$Upper\ limit\ SAIFI = 3 + 0.23\sqrt{length} + MIN\left(0.65, \frac{21}{length}\right)$$

$$Upper\ limit\ SAIDI = 330 + 55.2\sqrt{length} + MIN\left(160, \frac{5500}{length}\right)$$

Each of these upper limits is set to ensure the probability of an individual feeder exceeding it is about 1% in any year on average. That implies an expectation that approximately 1% of feeders should be non-compliant with each upper limit in any year.

The coefficients in the formulae were established by analysing actual performance data for the years 2014-15 through 2018-19. If future performance deteriorates relative to that past performance, then the proportion of feeders that are non-compliant would be higher than 1%.

The rest of this section explains how we established the functional form and the coefficients of these formulae.

Interruptions affecting the customers on a feeder can originate from an event on one of four parts of the electricity supply system:

1. Outside the distributors' network (exempt from the standard)
2. The distributors’ sub-transmission network (not reflected in these formulae)
3. The high-voltage part of the feeder (HV)
4. The low-voltage part of the feeder (LV).

Only HV and LV events are reflected in the formulae.

114 The coefficients in the formulae below are based on Length measured in km units.

D.3.1 Distinguishing between HV and LV events

Ausgrid was the only distributor to provide interruption data that separately identified HV and LV events. Using this data, we examined a range of heuristic rules that could be used to classify interruptions as HV or LV. For each candidate rule, we could compare the resulting classifications with the actual HV/LV breakdown. Our aim was to find a rule that would minimise the effect of any classification errors on our estimates of customer interruptions (CI, used for SAIFI) and customer-minutes of interruption (CMI, used for SAIDI).

Based on expert engineering advice and discussions with the distributors, we examined rules based on the proportion of customers affected by a given interruption. The intuition was that LV faults tend to affect a smaller proportion of customers (only those on an LV spur) than HV faults (which affect everyone downstream).

We determined that an LV-cutoff function of the following form would yield a useful classification of faults into HV and LV categories:

$$Maximum\ proportion\ of\ customers\ affected\ by\ an\ LV\ fault\ =\ MIN\left(1, \frac{A}{feeder\_length}\right)$$

Using trial and error, we determined a value for the parameter "A" that minimised misclassification errors in numbers of interruptions, CI, CMI and average duration for the Ausgrid data. We applied the same LV-cutoff formula for Endeavour and Essential to classify their faults as HV or LV.

D.3.2 HV upper limits

We found that historical actual levels of SAIFI for HV interruptions increased with the square root of feeder length. We found that the HV SAIFI upper limits corresponding to a 1% probability of exceedance were well described by a linear function of the actual HV SAIFI. Combining these two results yielded the intercept and the square root coefficient in the SAIFI formula above.

As documented above, we used an optimisation model to determine the HV SAIDI values that minimised the expected total social costs for each feeder. We found that these optimal SAIDI values also increased with the square root of feeder length. We found, as for SAIFI, that the HV SAIDI upper limits corresponding to a 1% probability of exceedance were well described by a linear function of the optimal HV SAIDI. Combining these two results yielded the intercept and the square root coefficient in the SAIDI formula above.

The upper limits for SAIFI and SAIDI were calculated using the single-feeder statistical model, which is documented in detail in a separate appendix.

D.3.3 LV upper limits

LV faults are more prevalent on feeders of shorter length. That is to be expected since our LV-cutoff function is proportional to the inverse length (ie, 1/length). While LV fault data tends to be exhibit greater variability (ie, noise) than HV fault data, we observed a statistically significant relationship between LV SAIFI and the inverse length function. We observed a similar significant relationship for LV SAIDI. We judged statistical significance in this case by the t-values for the inverse length coefficients, which were above 4 (for SAIDI) and 8 (for SAIFI).

By trial and error, we found a coefficient B for a 1% probability of exceedance cutoff function of the form B/length for each of LV SAIDI and LV SAIFI. These B values are used in the above formulae for the single feeder standards.