Independent Pricing and Regulatory Tribunal
New South Wales

REVIEW OF THE ELECTRICITY DISTRIBUTION RELIABILITY STANDARDS

Final Report

May 2021

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1 Executive summary

Following a request from the Premier, we have reviewed the NSW electricity distribution reliability standards to ensure that they reflect the needs and preferences of the people of NSW. To do this, we considered what it costs the electricity distribution networks (the distributors) to meet and report on reliability standards and the value that customers place on having a reliable supply.

The Premier specifically asked us to make recommendations that would lower network prices and deliver bill savings to NSW electricity customers. We consider that the changes we are recommending will put downward pressure on network costs, and electricity bills over time. Our recommendations will help the distributors identify the right type and level of investment, enable the adoption of new technology, provide a better deal for customers who receive very poor service and reduce red tape.

Many of our recommendations set the scene for longer term savings or efficiencies. For instance, changes to the standards may allow the distributors to reduce costs by changing the mix of assets they use to deliver services but they may not be able to take advantage of this until existing assets come to the end of their lives.[1] New reporting requirements will help the distributors take advantage of emerging technologies to improve services, lower costs and deliver better environmental outcomes.

Reliability standards play a fundamental role in ensuring customers receive a reliable, continuous supply of electricity. However, they are also a key driver of the cost of electricity supply. Over the past decade, the NSW distributors have made significant investments in their networks, partly driven by relatively high reliability standards. As the cost of these investments is passed on to customers through higher electricity bills, it is important to get the balance right.

We are recommending a number of changes including:

- Removing reliability standards that duplicate national arrangements
- Minimum standards for individual feeders and direct connections that better reflect an efficient long-term level of reliability
- Updating individual customer standards with a new guaranteed service level (GSL) scheme
- New reporting standards for distributed energy resources (DER), such as rooftop solar, wind turbines and battery storage, to increase the distributors' ability to host DER and increase exports to the network

1 Electricity distribution assets are typically long lived – some assets have an expected life of up to 50 years. As assets reach replacement age, the amended standards may lower costs. For example, by allowing the networks to reduce the amount of back-up infrastructure by not replacing some assets or to reduce the capacity of some assets, at a lower asset cost.

- New standards for standalone power systems (SAPS), which provide electricity to customers without going through the grid, and future changes to provide SAPS customers with the same protections as other customers
- Streamlined reporting and auditing requirements.

Our recommendations are set out in full on page 6 of this report. If adopted, they will be implemented in mid-2024.

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2 Introduction

Electricity outages cause disruption to customers and interfere with business, workplace and household activities. The NSW Government includes reliability standards in the operating licences of the NSW electricity distribution network providers, 'the distributors' (Ausgrid, Endeavour Energy and Essential Energy) to keep the number and duration of electricity outages within certain limits.

The distributors arrange their businesses to meet the reliability standards in their licences. The higher the level of reliability required by the standards, the more it costs the networks to meet them.[b] Costs associated with meeting the standards are periodically reviewed for efficiency by the Australian Energy Regulator (AER), and then passed through into customers' bills.

We have reviewed the level of reliability required of Ausgrid, Endeavour Energy and Essential Energy. We considered both the value and the cost of delivering different levels of reliability. We also looked at how the standards should be specified and what the distributors should be required to report on.

This report sets out our findings and recommendations and explains the analysis that supports them. The remainder of this chapter discusses the key findings of our review and the process we followed. It also lists our recommendations in full.

2.1 Overview of our findings and recommendations

We consider that a number of changes to the standards are needed. If adopted, these changes will be implemented in mid-2024. This timing ensures that the changes can be taken into account in the AER's next review of distribution prices. An overview of the key changes we are recommending is set out below.

2.1.1 Remove duplication between the NSW requirements and the national reliability incentive scheme

We recommend removing standards for overall network reliability from the NSW licences, as the national scheme provides adequate incentives to maintain and improve this. We recommend retaining individual feeder standards, direct connection standards and individual customer standards in the NSW licences, as the national framework does not provide adequate incentives for reliability at these levels.

b Additional costs come from maintenance to keep the chance of equipment failure low enough, available staff and spare parts to repair equipment and restore supply quickly enough when it does fail and having enough back-up (or redundant) infrastructure to work around a failure while equipment is being repaired.

2.1.2 Alter the minimum standards for individual feeders and direct connections to better reflect efficient long-term levels of reliability

We recommend moving away from setting individual feeder reliability based on classes of feeders and instead adopting minimum standards that vary directly with feeder length. We recommend setting the minimum standard for each feeder using a formula for each of two measures of reliability, reflecting the duration of outages (SAIDI) and their frequency (SAIFI).

The same two reliability formulas should apply to all NSW distributors. For the Sydney CBD we recommend maintaining individual feeder reliability standards at the current level. For direct connections, we recommend minimum standards calculated using the same formula for SAIDI and SAIFI as for non-CBD feeders and a proxy feeder length of 1 km. For very long feeders we recommend minimum standards based on a proxy feeder length of 500 km.

To develop the recommended SAIDI and SAIFI formulas we modelled the optimal level of reliability by finding the reliability with the lowest 'social cost' – the combined cost of providing reliability (the business costs of the distributor) and the value that customers place on it (measured as the value of customer reliability, or VCR). We then determined what minimum standards of reliability would be associated with this optimal level.[c] We consider that these feeder standards better reflect an efficient long-term level of reliability than the existing standards and will put downward pressure on network costs, and customer bills, over time.

Where individual feeders do not meet the minimum standards, distributors will continue to be required to report non-compliance and investigate options for improving reliability. Distributors should take steps to improve reliability where the benefits of doing so exceed the cost. Currently, all networks meet or exceed our estimated optimal SAIDI and SAIFI performance on most feeders in most years. We expect that around 1% of feeders will require investigation each year, which is consistent with the current standards and with our Draft Report.

2.1.3 Update the individual customer obligations by introducing a new guaranteed service level scheme

The existing scheme that sets service standards for individual customers has not been updated since 2004 and is in need of modernisation. Under the scheme, customers with poor service are able to apply for an $80 payment from their distributor. Distributors are required to take reasonable steps to notify customers about the scheme but uptake is currently very low, with fewer than 5% of eligible customers actually receiving payment.

[c] Setting the minimum standard at the optimal level would encourage over-investment in reliability, as distributors must ensure that their feeders meet or exceed the minimum standards wherever possible.

We recommend replacing the existing scheme with a two-tier scheme that distinguishes between poor and very poor service, with higher payments for eligible customers, a new cumulative outage standard and a more consistent approach to exclusions. We also recommend some drafting changes to clarify the steps distributors are required to take to notify customers about the scheme and to allow them to make payments using electronic funds transfer (EFT) rather than by cheque.

Compared with our Draft Report, we have revised both the thresholds for eligibility and the payments for level 1 and level 2 after considering stakeholder comments and additional data provided by the distributors. Consistent with our Draft Report, we continue to support key changes to the existing scheme in order to ensure that the individual customer standards are working as they should and that payments are adequate, taking into account inflation.

We compared the costs of the current and proposed schemes by looking at what the cost of each scheme would be if all eligible customers received payment. The combined cost of the changes we are recommending is in line with the cost of simply updating payments under the existing scheme to reflect the change in inflation since 2004.

While our proposed scheme is more targeted with fewer eligible customers, we expect the number of customers receiving a GSL payment will rise. Similar to the current obligations, distributors would be required to take reasonable steps to notify customers who are eligible for payment under the GSL. Distributors should report annually on the steps they have taken and the resulting uptake. We will use this information to inform our assessment of whether reasonable steps have been taken. If the number of payments made does not rise from its current very low level, then we are likely to direct distributors to take additional steps.

2.1.4 Introduce a reporting framework for distributed energy resources (DER) that can be altered as national arrangements develop

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
- Storage technologies, including batteries, thermal storage and electric vehicle (EV) charging.

We recommend requiring the distributors to disclose information relevant to the quality of service provided to DER customers. 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. DER reporting standards in the NSW licence would provide more data about the impact of export constraints on customers and inform future decisions on whether regulatory changes are required at either the national or state level.

Several reform processes aimed at efficiently integrating DER into the energy market are currently underway at the national level. We intend to update the NSW reporting standards as the national framework develops to ensure that the NSW scheme complements and does not duplicate national arrangements.

2.1.5 Ensure that customers who are served by standalone power systems (SAPS) have reliability standards in line with those of other customers

A SAPS is an electricity supply arrangement that is not physically connected to the national grid. 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.

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.

SAPS are not currently covered by the distributors' operating licences or the national economic regulation framework. However, the Australian Energy Market Commission (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. We support these changes.

Once this is done, we recommend including a number of additional reliability obligations for supply using distributor-led SAPS. These changes are aimed at ensuring that customers serviced by SAPS receive the same customer protections afforded to other residential and business customers. This is particularly important as distributors could move customers from the network to a SAPS without their explicit consent. We also recommend changes to ensure that the reliability standards do not discourage distributors from using SAPS when they are a cost-effective means of delivering a reliable supply of electricity to customers.

2.1.6 Streamline reporting and auditing requirements

Distributors 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 recommend the licence conditions be amended to require annual reports on compliance, except for the reporting on DER. We consider that more frequent publication of DER information is necessary and that distributors should be required to report this information every quarter. We also consider that IPART should have discretion to decide on the frequency and scope of audits based on reported reliability performance.

2.1.7 Changes to NSW reliability standards should be timed to feed into the 5-yearly pricing reviews undertaken by the AER

We recommend that changes to the reliability standards take effect from 1 July 2024. This timing would ensure both the distributors and the AER can take the revised standards into account in the next review of network prices. 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 pricing proposal before submitting it to the AER. We also recommend reviewing the standards every 5 years, to align with the AER's review cycle.

We consider that the distributors should commence publishing quarterly information on DER as soon as possible. The market and regulatory regime for DER is developing rapidly and accurate, up to date information is vital. We intend to issue a revised Reliability Reporting Manual to request the distributors to commence publishing this information on a voluntary basis until their licence is updated to reflect these requirements.

2.2 The review process

As part of our review we collected information, conducted public consultation, and undertook detailed modelling and 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.
- We released a Draft Report outlining proposed recommendations in October 2020 and sought stakeholder feedback. We received 7 submissions in response to the Draft Report.
- Following the Draft Report, we also received some additional information from the distributors and undertook some additional consultation.
- We took into account all views provided to us in coming to our final decisions.

2.3 Structure of this report

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

- Chapter 3 explains our draft recommendations on the role and objectives of the licences and what requirements need to be included to meet these objectives.
- Chapters 4 and 5 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 6 sets out our recommended guaranteed service levels and payments.
- Chapter 7 describes how the standards should take account of DER and two-way energy flows.
- Chapter 8 discusses how the standards provide for the rollout of SAPS.
- Chapter 9 explains when any new standards should take effect, how often standards should be reviewed, and the appropriate compliance and monitoring framework.

A copy of the terms of reference is provided in Appendix A. 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 a separate information paper. This information paper also includes some additional analysis on the impact of rainfall on feeder reliability.

Accompanying this Final Report are recommended revisions to the licence conditions and a revised Reliability Reporting Manual to take effect 1 July 2021 and a revised Reliability Reporting Manual to take effect 1 July 2024.

2.4 Complete list of recommendations

5 The NSW licences should require distributors to publish, as far as is reasonably practicable, daily progress updates to customers with information about how long it will take to restore supply after a Major Event Day outage. 23

6 The NSW licences should require distributors to collate data on planned outages that have occurred over the previous financial year and publish an annual report on their websites by 31 August of each year. 24

Individual feeder and direct connection standards

7 For non-CBD feeders less than 500 kilometres in length, the SAIDI standard should be set as a function of feeder length using the expression below. This should apply to all three distributors. 35

$$\text{SAIDI} = 262 + 108\sqrt{\text{Length}} + \text{MIN}(160, \frac{5500}{\text{Length}})$$

8 For non-CBD feeders less than 500 kilometres in length, the SAIFI standard should be set as a function of feeder length using the expression below. This should apply to all three distributors. 37

$$\text{SAIFI} = 3.1 + 0.44\sqrt{\text{Length}} + \text{MIN}(0.65, \frac{21}{\text{Length}})$$

9 For non-CBD feeders that are 500 kilometres or longer, the SAIDI standard should be set at 2688 minutes and the SAIFI standard at 13.0 interruptions. These standards are based on the reliability formulae for other non-CBD feeders and a 'proxy' feeder length of 500 kilometres to recognise the different relationship between feeder length and fault rates for very long feeders. 40

10 For CBD feeders (feeders forming part of the triplex 11kV cable system supplying predominantly commercial high-rise buildings, within the City of Sydney), the SAIDI standard should be set at 100 minutes and the SAIFI standard at 1.4 interruptions. These are the same as the current standards. 41

11 For direct connections, the SAIDI standard should be set at 530 minutes and the SAIFI standard at 4.2 interruptions. These standards are based on the reliability formula for other non-CBD feeders and a 'proxy' feeder length of 1 kilometre. 42

12 For feeders that exceed the standards for SAIDI and/or SAIFI, the distributors should follow a similar reporting and investigation process to the current licence. We recommend that distributors are required to: 44

– Report on and investigate causes of outages for feeders with reliability that breaches the standard

– Take reasonable steps to improve reliability, develop plans and undertake cost benefit analyses

– Improve reliability where the benefits exceed the costs unless distributors can satisfy IPART that it is reasonable not to do so.

Guaranteed customer service levels

13 For residential and small business customers supplied on a deemed standard connection contract, the NSW licence should include a revised guaranteed service level (GSL) scheme. If a distributor is unable to meet the GSL standards for a particular customer, then they should be obliged to make payment available to that customer on request. The GSL should specify the minimum levels of reliability and associated payments set out in the table below: 57

GSL	Ausgrid & Endeavour Energy	Essential Energy	Payment
Level 1	20 hours or 10 outages per calendar year	36 hours or 20 outages per calendar year	$120 at 1 July 2024, escalated annually by the change in inflation
Level 2	48 hours or 20 outages per calendar year	120 hours or 50 outages per calendar year	Typical annual distribution network service charge for residential customer

Note: Excluded interruptions are the same as those applying to individual feeder standards.

14 Under the proposed GSL scheme, the distributors should be required to: 59

– take reasonable steps to ensure eligible customers are aware of the scheme and follow any directions provided by IPART to take specific steps towards informing eligible customers

– report on the steps they have taken, how many customers were eligible, how many customers applied for payments and how many customers received payments

– take all reasonable steps to pay eligible customers within 12 weeks of receiving an application.

Distributed Energy Resources and Standalone Power Systems

15 The NSW licence should require distributors to publish information on distributed energy resources (DER) on a quarterly basis. This would provide more data about the impact of export constraints on customers and inform future decisions. We will amend the current Reliability Reporting Manual to include a request for distributors to disclose the same information on a voluntary basis until the new licence commences in 2024. 65

16 Recognising the growing importance of distributor-led standalone power systems (SAPS), the NSW Government should continue to progress legislative changes to incorporate them within both: 72

– the NSW Electricity Supply Act framework, and

– the National Energy Retail Law (New South Wales), on implementation of the AEMC's proposed legal and regulatory framework.

17 The NSW Government should ensure that legislative changes provide customers of distributor-led SAPS with the same protections afforded to grid connected customers. On commencement of those legislative changes, the NSW reliability standards should be extended to distributor-led SAPS as follows: 75

- for microgrids with feeder-like high voltage distribution lines the individual feeder standards should be set consistent with other non-CBD feeders (using the reliability formulas set out in recommendations 8 and 9)
- for all other distributor-led SAPS the minimum level of SAIDI should be set at 1817 minutes and the minimum level of SAIFI at 9.4 interruptions. These standards are based on the reliability formula for other non-CBD feeders and a 'proxy' feeder length of 200 kilometres in line with the current threshold for defining a long rural feeder.
- for customers supplied by distributor-led SAPS, the GSL scheme should apply as if those customers were connected to the grid
- where SAPS do not meet the reliability standards at the point of measurement, but deliver the required level of service to the end-customer, the SAPS should be deemed to be compliant with the reliability standards.

Commencement and review of distribution reliability standards

18 The revised licence conditions should come into force on 1 July 2024. 78

19 Distributors should be required to provide annual reports to IPART on their compliance with reliability standards, with flexibility for IPART to adjust report timing and frequency through the Reliability Reporting Manual. 79

20 The distributors should 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. 79

21 The NSW licence should allow IPART, as the licence administrator, the discretion to determine the frequency and scope of independent compliance audits, and that this will be done using a risk-based approach. 80

3 Role of the operating licence in determining minimum standards of reliability

Summary of our final decisions

The NSW operating licences should complement the AER's economic regulation of electricity distributors:

- The AER sets incentives for distributors to manage the costs and benefits of reliability through its Service Target Performance Incentive Scheme (STPIS).

We recommend that NSW no longer sets overall network standards:

- These standards are adequately provided for in the STPIS.

The NSW operating licences should continue to set minimum individual feeder standards and direct connection (individual customer) standards:

- Failure to meet individual feeder standards and direct connection standards (for high voltage business customers) should continue to require distributors to report, investigate and invest where appropriate
- Failure to meet guaranteed service levels for residential and small business customers should require distributors to make payments to impacted customers.

Electricity reliability is included in both the NSW operating licences and the AER's regulations, in particular, its Service Target Performance Incentive Scheme (STPIS). This is the first time IPART has looked at the reliability measures included in the NSW operating licences, and the first major review since the AER introduced the STPIS.

The NSW licences currently include 4 different reliability components:

- Overall feeder standards – which distributors must meet to comply with their operating licence
- Individual feeder standards – which distributors must report against, and require distributors to investigate and upgrade (where efficient) feeders that do not meet the standard
- Direct connection standards (which in the existing licences are called individual customer standards) – which are effectively individual feeder standards for customers directly connected to the sub-transmission network.
- Guaranteed service levels (which in the existing licences are called customer service standards) – which require distributors to provide a level of service to individual customers, or to make payments available to them.

Each of these requirements interacts with the national regulatory arrangements. The AER is the principal economic regulator for the NSW distributors and determines their revenue allowance. Through this process, the AER considers the efficient costs of meeting the NSW reliability requirements and incorporates investment incentives for the distributors.

We recommend removing duplication with the national regime and retaining other obligations within the NSW licence. Our final decisions are the same as our draft decisions, which were supported by stakeholders. The sections below discuss the issues associated with each of the components of reliability.

3.1 Overall network reliability is better left to the national regime

The STPIS is the main instrument the AER uses to regulate reliability. The AER introduced the STPIS to incentivise distributors to manage their reliability and invest in improvements where it is efficient to do so. The STPIS includes strong incentives that are automatically adjusted for changing costs and periodically adjusted for changing values of customer reliability to ensure the incentivised reliability level remains efficient over time.

While the NSW licence also includes overall network standards, these are based on a static or unchanging minimum level of reliability. Typically, the incentives provided under the STPIS vastly outweigh the minimum requirements set out in the NSW licence.[d] This was noted by Essential Energy, which stated:

> Given the operation of the national regulatory incentive framework, specifically STPIS, [the overall feeder standards] in the current licence conditions provides virtually no incentive for Essential Energy to adjust reliability levels.[1]

[d] In most instances, existing performance is far more reliable than the NSW reliability standards making it relatively easy for distributors to comply with the NSW licence.

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

- $68 million per year for Ausgrid
- $39 million per year for Endeavour Energy
- $47 million per year for Essential Energy.[2]

These financial incentives are balanced by operating expenditure incentives and capital expenditure (CESS) incentive schemes (see Box 3.1).

Box 3.1 The AER's reliability incentives

The STPIS

The AER applies a STPIS to the NSW distributors. The scheme offers incentives for business to improve their service performance to levels valued by customers. 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 bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5% of a distributor's revenue. The STPIS is balanced by the efficiency benefit sharing scheme and capital expenditure sharing scheme.

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 distributor to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast.

The EBSS effectively allows distributors to retail efficiency gains (or bear efficiency losses) for the duration of a regulatory period. Historically, this gave a long term benefit to the business equal to 30% of the saving with the remainder going to customers in the form of lower prices. The amount distributors keep has decreased due to decreases in the rate of return in the last 15-years.

The Capital Expenditure Sharing Scheme

The AER's capital expenditure sharing scheme (CESS) creates an incentive for distributors to keep new investment within forecasts. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast). The CESS allows a distributor to retain underspending against the forecast for the duration of the current regulatory period (which may be up to 5 years, depending on when the spending occurs).

The CESS ensures distributors keep 30% of the savings with the remainder going to customers in the form of lower prices. Unlike the EBSS this adjusts to changes in the rate of return.

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.

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.

If the reliability standards are set at the efficient level, the licence can ensure that level is met and customers receive 100% of the benefit. However, if the reliability standard is not set at an efficient level it could drive inefficient expenditure, and customers bear 100% of the cost.

HoustonKemp found that the AER's regulatory framework is more responsive to changes in the costs of providing reliability than the NSW operating licence. As this makes the STPIS better able to incentivise efficient investment, the STPIS should be the preferred mechanism.

However, HoustonKemp identified that the AER's incentive regime is no longer as balanced as initially designed. This is due to reductions in the underlying cost of capital over time, making the distributors' incentives under the STPIS and EBSS weaker than the CESS. This provides distributors with a stronger incentive to reduce capital expenditure relative to reliability and operating expenditure.

The AER recently indicated that it is currently scoping a broad review of its incentive schemes. We encourage the AER to look into the imbalance in incentives and adjusting incentive rates as part of this review.

3.2 Individual feeder standards would add value

We consider that the NSW licence should complement the AER's reliability incentives and fill any gaps in that regime. We found that this requires keeping the individual feeder and individual customer standards as these are not adequately covered by the STPIS.

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).

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 on improving reliability where it is most needed. Without the individual feeder standards, the distributor may choose to invest in other projects (e.g. with a higher rate of return), while continuing to provide low levels of reliability in some areas, 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.

3.3 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. We consider that the licences should retain direct connection standards.

3.4 Customer level standards have a role in recognising poor service

To meet an individual feeder standard a distributor has to provide sufficient reliability to meet the standard on average across the feeder. A distributor can comply with its individual feeder standards while providing some customers very low levels of reliability. Applying customer level standards via a guaranteed service level scheme provides some compensation for customers with very poor service. The guaranteed service level payments operate as an acknowledgement that the distributor has not met the level of service it guarantees.

Recommendation

1 To ensure that the NSW standards complement but do not duplicate national standards, the NSW licences should no longer include overall feeder standards. They should continue to include standards for individual feeders, direct connections (for larger customers) and individual customers.

4 How reliability should be measured in the NSW standards

Summary of our final decisions

The licence standards should continue to use SAIDI and SAIFI metrics:

- This is consistent with the national reliability guidelines issued by the AER
- It facilitates assessment, comparison and benchmarking of all distributors in the NEM
- It minimises regulatory burden.

Excluded events under the licence should be aligned with the AER's STPIS and reliability guideline:

- This minimises regulatory burden.

The current approach to identifying Major Event Days (MEDs), the Beta Method, should be retained:

- IPART will continue to assess any proposals for an alternative method on a case-by-case basis.

The licence should require additional reporting on customer restoration rates after an MED and planned outages.

Having decided to maintain individual feeder and direct connection standards, our next step was deciding how to express the standards, the types of events to be excluded when measuring performance against the standards and the required levels of performance.

This chapter sets out our final recommendations on these issues. Our final recommendations on the levels of reliability in the standards and the reporting and investigation process that would be triggered when these levels are exceeded are discussed in Chapter 5.

4.1 What measures of reliability should be used in the licence standards?

Under the current licence conditions (see Appendix B), feeder standards are set with reference to the average duration and frequency of unplanned interruptions. These 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 experiences, 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.

We sought comment on whether these measures should continue to be used in the standards. Stakeholders support continuing measuring reliability using SAIDI and SAIFI.[3] Ausgrid[4] and Endeavour Energy[5] note that these metrics are well defined and widely used, which adds to their credibility.

The SAIDI and SAIFI metrics in the licence are consistent with the national reliability guidelines issued by the AER for measuring distribution network reliability.[6] We consider that using the 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).
- Minimises regulatory burden by ensuring that the NSW distributors measure and report reliability performance similarly for the NSW Government and the AER.

In contrast, the use of different reliability measures may result in the distributors incurring additional reporting and compliance costs and potential confusion in interpreting performance against the different obligations.

Final recommendation

2 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.

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

Excluded interruptions are events that are disregarded when measuring reliability (to assess performance against the standards) so that the distributors are not penalised for events that are generally considered beyond their control.

At present there are differences between the excluded events under the licence and those in the AER's national reliability guidelines and STPIS.

We recommend changing the exclusions in the NSW licence conditions to align them with the national reliability regime. The proposed changes are detailed in Box 4.1 below (the italicised events are the excluded interruptions that we recommend adopting from the STPIS exclusions, to facilitate the proposed alignment). We consider that this approach will reduce regulatory burden and compliance costs for the distributors and subsequently costs for consumers, consistent with the objective of this review. Stakeholders support this approach,[7] with Essential Energy citing the impracticality of reporting against different sets of exclusions as a key reason to align them.[8] Ausgrid also notes that streamlining compliance efforts through aligning the excluded interruptions would ultimately promote affordability for customers by reducing regulatory reporting costs.[9]

Final recommendation

3 The events to be excluded from measured interruptions should be aligned with the AER's Distribution Reliability Measures Guidelines and Service Target Performance Incentive Scheme (STPIS).

Box 4.1 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 alignment of exclusions, some events that previously appeared in the NSW licence condition are no longer excluded or are worded slightly differently. The proposed changes and the rationale behind them are summarised in the table below.

Table 4.1 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 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 the 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 the 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.
N/A	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.

4.3 How should major event days be treated?

Under the current licence standards and the national regime, the distributors may also exclude any interruption to the supply of electricity that commences on a major event day (MED).[e] MEDs are excluded from reliability performance measurement as they are not representative of a typical day in terms of reasonable network availability. They are typically caused by severe weather conditions.[10] The MED exclusion 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 Method to identify MEDs.[11]

The IEEE Standard's MED method has been in the NSW licence conditions since the licences were first 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. Given its use in the AER's STPIS, maintaining the current MED approach would also minimise regulatory burden as the distributors can report consistently to the state and national regulators.

However, it will not guarantee consistency. The AER has considered several requests to apply different estimation methods and has accepted these in the past. Endeavour Energy asked that IPART allow for alternatives to the Beta Method when calculating MEDs, as the AER had accepted Endeavour Energy's use of the Box-Cox transformation method in the last two regulatory determinations. Box 4.2 contains more information on Endeavour's proposed alternative approach and how this has been considered by both the AER and IPART in the past.

We note that the current licence conditions do allow for the distributors to seek IPART's approval to apply a different threshold for identifying MEDs.[f] Our final recommendation is to retain the current licence conditions on identifying MEDs. IPART will continue to assess each proposal for an alternative to the Beta Method on a case-by-case basis, based on the supporting evidence provided.

Final recommendation

4 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 should be maintained. This will encourage the networks to become more resilient to changes in climate and weather over time.

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e Under the current licence, MEDs are identified based on a statistical process under the *IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices* known as the Beta Method, which is used to establish a daily SAIDI threshold. See, eg, Ausgrid Distributor's Licence under the Electricity Supply Act 1995 (NSW), Schedule 6. See also AER, Distribution Reliability Measures Guideline 2018, p 8.

f According to the IEEE, the Beta Method is to be used provided that the natural log transformation of the daily SAIDI data results closely resembles a Gaussian (normal) distribution. 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. See, e.g. Schedule 6 to the licence conditions of Ausgrid and Endeavour Energy.

Box 4.2 Endeavour Energy's alternative calculation for determining MEDs

The AER allowed Endeavour Energy to use the Box-Cox transformation method in determining MEDs for the 2015-2019 regulatory period.[a] In making 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.[b] We note that ETSA (now known as South Australia Power Networks), reverted back to using the Beta Method in its 2015 determination.[c]

In 2017, Endeavour Energy sought IPART's approval to use the Box-Cox transformation method to identify MEDs as part of its compliance with the NSW reliability licence conditions. We did not agree to this request. We considered that the Box-Cox transformation method was not appropriate for the following reasons:

- The Box-Cox transformation does not provide a normal distribution and fails 3 of the 4 tests of 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[d] 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.

a AER, Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19, Attachment 11: Service target performance incentive scheme, April 2015, p 7.

b AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19, Attachment 11: Service target performance incentive scheme, November 2014, p 21–23.

c AER, Final Decision SA Power Networks determination 2015-16 to 2019-20, Attachment 11: Service target performance incentive scheme, October 2015, p 10.

d This would make year-to-year comparisons of network performance and system-to-system performance more difficult.

4.3.1 Our approach to major event days encourages 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.[12] The impact of the 2019-20 NSW bushfires on people, businesses and the environment was unprecedented. 5.4 million hectares[13] of land was burnt which damaged power poles and other electricity infrastructure leaving many customers without power.

We consider that the current approach to identifying MEDs encourages the distributors to manage the resilience of their networks over time. The IEEE Standard uses a beta of 2.5. That is, it sets a daily SAIDI threshold for identifying an MED (based on the previous 5 years of reliability performance) so that the probability of exceeding it is 0.00621, equivalent to 2.3 MEDs per year.[g] To the extent that climate change increases the number of severe weather events, some unplanned interruptions previously identified as MEDs may no longer be excluded from the measurement of performance against the licence standards.

g This is considered by the IEEE to be an appropriate or reasonable level of MEDs. *IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices*, p 22, 28.

As set out in Chapter 3, the AER's STPIS (which also excludes MEDs using the IEEE's Beta Method) is the key driver of overall network reliability through the incentives it creates for distributors to achieve an efficient level of reliability. The licence will complement the AER's framework by requiring the distributors to report against a minimum or safety net level of service. We consider that the current exclusions are appropriate in this context and that reporting against the licence standards will provide important information on the resilience of the network over time.

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

We are recommending that distributors be required to publish daily progress updates on the restoration of electricity supply after a MED, as far as is reasonably practicable. This will increase customers' visibility of these events when they impact their electricity supply.

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 low and outweighed by the benefits to customers.

This is similar to what we proposed in the Draft Report but in response to feedback, we have decided that the requirement should apply only as far as is reasonably practicable. Essential Energy proposed a similar approach in its submission to the Draft Report, submitting that the requested information should be provided on a 'best endeavours' basis, which avoids locking in any compliance requirements.[h] Essential Energy submitted that there are a number of difficulties with the introduction of this requirement without such qualification, including that:

- a major outage can take a few days to be declared a MED, and yet compliance is required on a daily basis
- compliance with the level of detail required (and, in particular, until the last customer supply is restored) will be difficult without improvements in low voltage visibility.

[h] According to Essential Energy, its bushfire experience in 2019-20 included daily reporting to government of impacted customers, which was very manual, resource intensive and impacted restoration times as field workers were required to undertake this administrative work. See Essential Energy, Submission to the Draft Report, p 16.

We recognise the challenges in reporting on customer restoration rates after an MED and we understand that there will be a degree of error in any such reporting, in particular where there is a need to balance reporting and restoration efforts. Amending the relevant section of the Reliability Reporting Manual so that the distributors are required to meet this condition as far as is reasonably practicable will allow the distributors a degree of flexibility to strike an appropriate balance between the accuracy of reporting and the regulatory burden it imposes.[i]

Final recommendation:

5 The NSW licences should require distributors to publish, as far as is reasonably practicable, daily progress updates to customers with information about how long it will take to restore supply after a Major Event Day outage.

4.4 Can the current reporting on planned outages be improved?

Distributors are required to give consumers 4 days' notice of planned outages including the expected duration of the outage.[j] This requirement is in place to ensure that customers are given adequate notice of an interruption and to ensure that distributors properly plan for such outages. While distributors report to the AER on planned outages[k] we consider that this information is not presented in a consumer-friendly manner.[l]

We recommended a licence amendment to require distributors to publish information on planned outages, to increase the visibility of these events when they impact customers' electricity supply reliability. We consider that any additional costs associated with this reporting are likely to be low and outweighed by the benefits to customers.

We recommend that by 31 August of each year, the distributors are required to publish 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.

i We note that the electricity network safety regime requires distributors' safety management systems to comply with Australian Standard *AS 5577*. *AS 5577* requires distributors to reduce certain risks 'as low as is reasonably practicable'. Therefore, this concept is familiar to the industry, regulator and auditors.

j Note that in NSW, a shorter notice period may be accepted if it is agreed in writing by the distributor and the customer. Rule 90(1)(b) of the National Energy Retail Rules.

k Distributors report on planned interruptions to the AER via annual Regulatory Information Notices (RINs).

l In response to the Issues Paper, the NSW Farmers Association suggested additional reporting on planned outages. NSW Farmers Association, Submission to Issues Paper, April 2020, p 16.

This is consistent with the approach proposed in our Draft Report. Essential Energy submitted that "with some minor process improvements to capture high level reasoning for the time being exceeded on a planned outage, this requirement can be met".[14] However, Endeavour Energy considered that requiring reporting on planned outages may have adverse impacts, e.g. the additional scrutiny of planned outage data may incentivise distributors to:

- undertake less planned outage work in favour of more live work or at the risk of more unplanned interruptions due to asset failure
- lengthen outage estimation windows, which would impact the transparency of restoration performance.[15]

It is not clear to us that the reporting of planned outage data would incentivise such undesirable behaviour by the distributors. Our intention is that distributors follow the same processes for scheduling and undertaking this work but increase the amount of information available around it. We note that the details of this reporting requirement are set out in the Reliability Reporting Manual. If we observe any demonstrable negative impact of this requirement once it has been implemented, then IPART can reconsider the suitability of the requirement.

Final recommendation

6 The NSW licences should require distributors to collate data on planned outages that have occurred over the previous financial year and publish an annual report on their websites by 31 August of each year.

5 Setting individual feeder and direct connection standards

Summary of our final decisions

Individual feeder standards for SAIDI and SAIFI for distributors' non-CBD network should be set as a function of feeder length using the expressions below:

- $SAIDI = 262 + 108\sqrt{Length} + Min(160, \frac{5500}{Length})$
- $SAIFI = 3.1 + 0.44\sqrt{Length} + Min(0.65, \frac{21}{Length})$
- This reflects the strong relationship we found between feeder length and an individual feeder's long-term efficient level of reliability for non-CBD feeders.

For feeders longer than 500 km, the standard should be calculated using a feeder length of 500 km.

Individual feeder standards for SAIDI and SAIFI for Ausgrid's CBD network should be maintained in line with Ausgrid's current licence conditions, which are:

- SAIDI = 100 minutes per customer per annum
- SAIFI = 1.4 per customer per annum.

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

Distributors should report and investigate causes of SAIDI and SAIFI for feeders whose reliability is worse than the levels given by the formulae above:

- We expect that on average only 1% of feeders will exceed the standards in any year, given natural variation in such variables as weather.

Having decided how to express the standards and the types of events to be excluded, our next step was to consider how to set the set reliability standards for individual feeders and the approach to investigating and reporting on these feeders when they exceed the standards. This chapter explains how we developed our final recommendations on these issues, including how we took account of stakeholder feedback on our Draft Report and the subsequent analysis we have undertaken.

5.1 How did we set SAIDI standards for non-CBD feeders?

We recommend a new approach to setting the SAIDI standards for non-CBD feeders, which reflects the long-term efficient levels of reliability for each feeder. Our analysis suggests that the current approach to setting the standards does not strike a good balance between the distributors' costs and the customer benefits associated with these levels of reliability. Instead, we recommended setting the SAIDI standards for feeders by modelling the trade-off between the network costs of providing a certain level of reliability and the costs of outages to customers and finding the point at which the total cost is at its lowest.

We developed an approach comprised of two main stages:

1. Modelling the efficient level of reliability across different individual feeders.
2. Developing individual feeder standards that reflect our estimate of the long-term efficient levels of reliability.

This approach is consistent with what we proposed in our Draft Report. While stakeholders were generally supportive of this new approach, they did raise some concerns with aspects of the modelling underpinning it and how the results might be interpreted and used. In developing our final recommendations on the SAIDI standards we have taken this feedback into account, as well as undertaken subsequent analysis.

As a result, to develop our recommendations for the Final Report we have updated the modelling of the efficient level of reliability and the calculation of individual feeder standards. This involved re-estimating fault rates for Essential Energy, updating VCR data for Ausgrid, re-running the optimisation and single-feeder statistical models for Essential Energy and Ausgrid, and re-estimating the formulae that expresses the SAIDI standard.

The approach we took is discussed below, as well as the changes we made between Draft and Final Reports.

5.1.1 Modelling the efficient level of reliability

We engaged Nuttall Consulting to construct a model that finds the configuration for a given feeder that minimises its total social cost, which comprises:

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

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.

The model evaluates which combination of a stylised distributor's network design elements and supply restoration options lead to the lowest social cost. The model outputs indicate an efficient level of reliability based on a network that is less expensive to own and operate than the current network design, but imposes a higher level of expected unserved energy on customers (i.e. the modelled efficient level of SAIDI is higher than the modelled existing level). The model indicates a strong, but nonlinear relationship between feeder length and an individual feeder's long-term efficient level of reliability. However, this relationship is clearly different for very long feeders.

In response to our Draft Report, stakeholders raised a number of concerns with our modelling of efficient costs:

- Around selected inputs and assumptions in our modelling of efficient costs, which inform the SAIDI (and SAIFI) standards for individual feeders[16]
- That our modelling results may be interpreted and used outside the scope for which they were intended (e.g. by the AER to justify lower costs in a future price determination).[17]

In particular, Essential Energy suggested modifications to the high voltage/low voltage (HV/LV) allocation of interruptions[18] and provided further data to IPART for consideration. The distributors also expressed concern that the model did not account for exogenous factors. Ausgrid considered that exogenous cost drivers, such as technology changes, rising temperatures and extreme weather need to be acknowledged.[19] Essential Energy also noted that more than half of unplanned outages are caused by adverse weather and environment, while 30% are due to equipment failure.[20]

Box 5.1 sets out further information on the modelling approach we have used. Following that is an explanation of the changes we have made to modelling efficient costs since our Draft Report.

[m] To estimate this, we had regard to the AER's latest estimates of the value of customer reliability (VCR) for different customer types and climate zones, and asked distributors to provide estimates for each feeder.

Box 5.1 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.

Following our Draft Report we received additional information on the Essential Energy network including the split between HV and LV feeders and the fault rates. We used this updated information in our modelling for the Final Report.

Further detail on the approach, inputs and modelling assumptions we have used is included in a separate information paper on our modelling approach. We have consulted with each of the distributors over several workshops in developing the models. Where possible, we have used publicly available information (e.g. information reported by the distributors to the AER) in our modelling.

Changes made since our Draft Report

Since our Draft Report, we have updated our modelling of the efficient level of reliability by:

- For Ausgrid:
  - updating estimates of the VCR for each feeder based on information Ausgrid provided to us after the Draft Report was released (the Box below explains the importance of VCR in the modelling)
- For Essential Energy:
  - excluding feeders longer than 500 km, as the fault rates for these feeders appeared anomalous (i.e. these very long feeders experience significantly lower fault rates per kilometre of length than shorter feeders)
  - calculating HV fault rates and durations based on an HV/LV allocation of interruptions that Essential provided to us after the Draft Report was released.

Box 5.2 The importance of the Value of Customer Reliability (VCR)

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.[a] 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.[b]

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.

For the Draft Report, Essential Energy and Endeavour Energy provided these estimates and we used them in our modelling. For Ausgrid we developed our own estimate of VCRs for each feeder. Ausgrid has subsequently provided information on feeder-specific VCRs, which we have used to inform our Final Report recommendations.

a AER, *Values of Customer Reliability – Final Decision*, 2019, p 9.

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

The change in modelled efficient SAIDI between the Draft and Final Report recommendations is set out in the tables below. For Ausgrid, while there were some changes in the VCR at an individual feeder level, overall the new data did not change the results measurably.

For Essential Energy, there was a clear change to the relationship between fault rates and feeder length beyond 500 km. Our rainfall analysis (see the separate information paper on our modelling approach) provides some statistical confirmation that feeders in arid regions will experience significantly lower fault rates per kilometre of length. The use of Essential Energy's classification of interruptions as HV or LV, instead of the heuristic rule we employed in the Draft Report, is an improvement in accuracy. The heuristic rule was based on classification data from the Ausgrid network, which differs in many important respects from the Essential Energy network. For Endeavour Energy, the results are unchanged from the Draft Report.

Table 5.1 Ausgrid modelled efficient SAIDI – draft and final (mins pa)

Reliability	Urban	Short Rural	Long Rural
Optimised SAIDI - Draft	65.5	162.6	NA
Optimised SAIDI – Final	64.7	160.0	NA

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

Table 5.2 Essential modelled efficient SAIDI – draft and final (mins pa)

Reliability	Urban	Short Rural	Long Rural
Optimised SAIDI - Draft	72.8	180.5	515.5
Optimised SAIDI - Final	133.1	293.5	660.2

Table 5.3 Endeavour modelled efficient SAIDI –draft and final (mins pa)

Reliability	Urban	Short Rural	Long Rural
Optimised SAIDI - Draft	77.4	173.1	NA
Optimised SAIDI - Final	77.4	173.1	NA

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

We acknowledge that there may be a difference between the modelled efficient performance of a feeder and its efficient reliability in practice. This results 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 of historical interruption data, 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 efficient level of reliability on average across each of the feeder types. We also note that the second stage of our approach takes account of some of these differences, by setting the standard substantially below our estimate of the long-term efficient level of reliability. We consider that this is appropriate so that the minimum level of performance required by the standards allow for expected variation from the estimated long-term efficient levels. It means the distributors will only be required to investigate and report on feeders where performance is substantially worse than efficient levels.

As with the Draft Report results, the modelling indicated an efficient level of reliability based on a network that was less expensive to own and operate than the modelled existing network design.[n] Table 5.4 compares the difference between our estimated network cost of the existing level of SAIDI and our estimated network cost of the optimised level of SAIDI from the Draft Report to the Final Report estimates.

The gap between existing and optimised network costs has narrowed for all three distributors and, in particular, for Essential Energy. The difference is due to:

- A change to the way we estimated network costs for the existing feeder configurations.[o]
- The removal of longer feeders and the updated HV/LV fault classifications for Essential Energy. The net effect of those changes is that the fault rate for Essential Energy has doubled. That means fewer opportunities to save network costs.

Table 5.4 Difference between existing and optimised network costs ($m)

	Draft Report	Final Report
Ausgrid	121.6	105.3
Endeavour	180.7	155.5
Essential	203.2	50.6

In response to the Draft Report, all three distributors expressed concern with the cost reductions implied by our modelling. Ausgrid noted that is has significantly reduced expenditure in recent years and expressed concern with how we presented the modelling in our Draft Report. Ausgrid considered that our Draft Report did not make it clear that:

- The existing network was developed over more than 50 years
- Network assets have lives of 40 to 50 years meaning that change would be slow
- The modelled efficient cost is therefore theoretical and cannot be practically achieved
- The most efficient solution will change over time.[21]

Essential Energy also stated that the modelled efficient costs are not achievable in an existing network. Essential Energy encouraged IPART to make it clear to stakeholders that our outputs do not reflect potential efficiency gains that could be achieved in practice.[22] Endeavour Energy noted that the model is highly simplified.[23] Energy Networks Australia considered that 'that it would be inappropriate to rely on the model for purposes separate to informing IPART's NSW reliability standards review.'[24]

n The modelling found that it was optimal to reduce the length of the N-1 portion of a feeder. That implies slightly higher SAIDI, lower network cost, and a lower social cost overall.

o For the Draft Report, the process of deducing the cost of delivering the existing SAIDI included a constraint that was designed to ensure restoration times were not unrealistically short. Subsequently, we found that this constraint was unnecessary and that it artificially inflated the costs attributed to the existing network. For the Final Report, we have estimated costs of the existing network without that constraint. That decision has reduced the existing cost estimates for all three networks, relative to the Draft Report costs. Therefore the cost savings through optimisation has been reduced. The decision on whether to include or exclude that restoration time constraint has no effect on the standards. The constraint only affects the estimate of existing SAIDI, which is not part of the standard.

The levels of modelled costs should not be interpreted as the full costs of service delivery, as the optimisation model does not attempt to capture all costs.[p] This means total costs for a feeder are likely to be understated both in the existing and optimised cases. However, the cost differences between these cases remain valid, and we consider that they can be used for the purpose of calculating the efficient level of reliability. We consider that the SAIDI and SAIFI estimates for an optimised feeder are consistent with the least social cost configuration of assets. That is, our optimised feeder estimates represent the best available balance of network and customer-inconvenience costs.

We further note that:

- We do not use the standard to require a distributor to mimic our optimal asset configuration. We only require the distributors to match the SAIDI and SAIFI performance that an optimal feeder would deliver.
- Our representation of the existing performance of an individual feeder is hypothetical. We do not have access to information on the actual values of the 4 planning criteria for individual feeders. We have had to deduce these existing values by making certain informed hypotheses about how the existing feeder is configured to deliver the observed SAIDI and SAIFI performance. This hypothetical process means that our existing cost estimates are subject to a degree of uncertainty.
- The hypothetical and uncertain nature of our cost estimates for the existing network means that the cost reductions available through optimisation are also subject to those uncertainties. For this reason, these cost reduction estimates should not be employed for any purpose beyond the optimisation work described in this report. In particular, our estimates of cost reduction through optimisation were not designed to inform price regulatory decisions for the distributors.

While the cost differences between the existing and optimised cases should not be used for purposes beyond this report, we consider that the reliability standards we are recommending should put downward pressure on network costs, and electricity bills, over time. While the distributors cannot immediately deliver these levels of reliability at a lower cost, they should consider how to move towards them when evaluating the type and level of investment required for replacement and growth assets. Electricity distribution assets are typically long lived – some assets have an expected life of up to 50 years – but changes to the standards allow the distributors to reduce costs by changing the mix of assets they use to deliver services when existing assets come to the end of their lives. As assets reach replacement age, the amended standards should lower costs. For example, by allowing the networks to reduce the amount of back-up infrastructure by not replacing some assets or to reduce the capacity of some assets, at a lower asset cost.

p It only considers costs that vary when the planning criteria for a feeder are changed. The planning criteria that are varied in the optimisation are: portion of the feeder length that is secured (i.e. the N-1 portion), percent of load at risk after restoration but before repair, restoration time target, and repair time target.

5.1.2 Using the model outputs to develop individual feeder standards

The second stage of our approach involves taking the outputs of stage 1 and undertaking further analysis to decide what level to set the standard for each feeder. Our approach involves 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).

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

Deciding whether to maintain the existing feeder types

The first step in developing individual feeder standards was to decide whether we should maintain the existing feeder categories for non-CBD feeders, i.e. urban, short-rural and long-rural.[q] These categories apply under the existing licence and the National Reliability Guidelines.

As noted above, our modelling found a strong relationship between feeder length and the efficient long-term reliability of individual feeders. With the exception of very long feeders, 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 kilometre 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.

Given the strong relationship between feeder length and the efficient level of reliability for individual feeders, we decided that the standards for all (non-CBD) feeders should be determined based on feeder length only,[r] regardless of feeder category.

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.

q Reliability standards for Ausgrid's CBD feeders are discussed in section 5.5 below.

r We note that including the maximum demand per kilometre increased the complexity of the formulae we used but did not significantly improve the strength of the statistical relationship.

Deciding whether to set a different standard for each distributor

The current individual feeder standards set out the same or similar SAIDI standards for each distributor.[s] Although our modelling in stage 1 reflects 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 consider 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 Energy).

Adjusting for variation in feeder performance

We considered that the minimum level of performance required by the standards should allow for expected variation from the estimated long-term efficient levels[t] and that the distributors should only be required to investigate and report on feeders where performance is substantially worse than efficient levels. As set out in Chapter 3, the AER sets incentives for the distributors to manage the costs and benefits of overall reliability through its STPIS. We decided to set the standard based on a probability of exceedance of 1%. The 1% benchmark should be achieved as long as the network is efficiently designed and managed.

Setting recommended standards for SAIDI

We 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.[u] The single-feeder model calculates the 1 percentile SAIDI levels for every individual feeder in each of the three networks. We then used regression analysis to establish a relationship between the individual feeder 1 percentile levels and feeder length. This is the formula that expressed the SAIDI standard.[v]

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s 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).

t This takes into account annual variation and other feeder-specific factors that cause interruptions but that we were not able to quantify for modelling purposes.

u One of the inputs to modelling the efficient level of reliability is average fault rates and durations, which is based on actual levels over the 5 years up to and including 2018-19. These inputs are used to model the performance of the 'existing' network (based on actual performance but involving some deductive reasoning to estimate unobservable parameters). The model then looks for optimal solutions that are better than the modelled 'existing' performance.

v The separate information paper on our modelling approach explains how we established the functional form and the coefficients of this formula.

Once we had the revised modelled results for optimal SAIDI we ran them through our single-feeder model to determine the 1 percentile level of SAIDI relative to the efficient level at average fault rates and durations. We then again used regression analysis to establish a relationship between the individual feeder 1 percentile levels and feeder length.

Our SAIDI formula is set out below:

$$SAIDI = 262 + 108\sqrt{Length} + MIN(160, \frac{5500}{Length})$$

To derive this formula:

- We took the new 1 percentile levels and used them to estimate (by regression) revised formulae for the upper limit of HV SAIDI as a function of the square root of length.
- We added the term for the upper limit of LV SAIDI from the Draft Report analysis.
- We solved for the intercept terms (keeping the other coefficients) that ensured a 1% non-compliance rate of feeders on each of SAIDI and SAIFI on average across the state.

We took the last step, adjusting the intercept, for the following reason. Interruptions that occur on the HV part of the network may be correlated with interruptions that occur on the LV part of the network. For example, tree infall during a storm may affect both HV and LV assets in the same vicinity. On the other hand, effects of equipment failure would be isolated to the network that equipment is located in. In general, we have no way of measuring that correlation. The standard must apply to faults that occur either on the HV network, the LV network or both. The correlation rate, whatever it is, will be reflected in the intercept term.

Consistent with the method adopted in the Draft Report, our objective was to determine a standard formula that would lead to 1% non-compliant feeders on average across the whole state. We solved for the intercept value that met that requirement.

The Final Report standard formula differs from the Draft Report formula in the intercept term but also, and primarily, in the coefficient for the square root of length term. The main driver of the higher coefficient is the higher fault rates for Essential Energy that arose when we excluded feeders longer than 500 km and adopted Essential Energy's own HV/LV classification data.

Final Recommendation

7 For non-CBD feeders less than 500 kilometres in length, the SAIDI standard should be set as a function of feeder length using the expression below. This should apply to all three distributors.

$$SAIDI = 262 + 108\sqrt{Length} + MIN(160, \frac{5500}{Length})$$

5.2 How did we set SAIFI standards for non-CBD feeders?

We also recommend a new approach to setting the individual feeder SAIFI standards for non-CBD feeders, which reflected the modelled existing level of SAIFI. In developing our final recommendations we have taken stakeholder feedback on our Draft Report into account as well as undertaken subsequent analysis.

As with SAIDI, we also consider that the levels of SAIFI specified in the standards should be informed by the long-term efficient levels of reliability. However, the AER's VCR estimates are expressed in units of $/kWh. This does not specifically reflect the impact of frequent, short interruptions, and is better suited to estimating the impact of the duration of interruptions (measured via SAIDI) rather than the frequency of interruptions (measured via SAIFI). Hence we were less confident in our optimal SAIFI estimates. 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 (modelled) existing levels of performance, rather than our estimate of optimal SAIFI. This approach is consistent with the approach proposed in our Draft Report, which was supported by stakeholders.

As with SAIDI, we found that there is a strong relationship between feeder length and the (modelled) existing SAIFI of individual feeders. Therefore, we considered that 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 consider that the minimum level of performance required by the standards should allow for expected variation from the estimated long-term existing levels and that the distributors should only be required to investigate and report on feeders where performance is substantially worse than existing levels. We decided to set the standard based on a probability of exceedance of 1%.

We developed a single-feeder statistical model that allows us to determine the 1 percentile level of SAIFI relative to the existing levels at average fault rates and durations. The single-feeder model calculates the 1% SAIFI levels for every individual feeder in each of the three networks. We then used regression analysis to establish a relationship between the individual feeder 1 percentile levels and feeder length. This is the formula that expressed the SAIFI standard.[w]

To develop our final recommendations we updated the modelling of the existing level of reliability and the calculation of individual feeder standards, as we did for SAIDI. This involved re-estimating fault rates for Essential Energy, updating VCR data for Ausgrid and re-running the optimisation model for Essential Energy and Ausgrid.

w The separate information paper on our modelling approach explains how we established the functional form and the coefficients of this formula.

Once we had the revised modelled results for existing SAIFI we ran them through our single-feeder models for Essential Energy and Ausgrid to determine the 1 percentile level of SAIFI relative to the existing level at average fault rates and durations. We then again used regression analysis to establish a relationship between the individual feeder 1 percentile levels and feeder length.

Our SAIFI formula is set out below:

$$SAIFI = 3.1 + 0.44\sqrt{Length} + MIN(0.65, \frac{21}{Length})$$

As with SAIDI, the Final Report standard formula differs from the Draft Report formula in the intercept terms but also, and primarily, in the coefficient for the square root of length term. The main driver of the higher coefficient is the higher fault rates for Essential Energy that arose when we excluded feeders longer than 500 km and adopted Essential Energy's own HV/LV classification data.

Final Recommendation

8 For non-CBD feeders less than 500 kilometres in length, the SAIFI standard should be set as a function of feeder length using the expression below. This should apply to all three distributors.

$$SAIFI = 3.1 + 0.44\sqrt{Length} + MIN(0.65, \frac{21}{Length})$$

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

We have calculated the individual feeder standards resulting from applying our final recommendations for a range of feeders, which are shown in the table below. Compared to the current standards, our final recommendations result in the following for different feeder types:

- Urban: a higher level of SAIDI and slightly higher levels of SAIFI for Ausgrid and Endeavour Energy's feeders.
- Short rural: a lower level of SAIDI and SAIFI for most feeders (but a slightly higher level of SAIDI for country feeders).
- Long rural: a higher level of SAIDI and a slightly higher level of SAIFI for all feeders.

Table 5.5 Individual feeder standards for typical feeders

Feeder type	Length (km)	Current SAIDI	Draft SAIDI	Final SAIDI	Current SAIFI	Draft SAIFI	Final SAIFI
Typical urban feeder	5	350/400[a]	613	663	4/6[b]	4.2	4.7
Typical exurban short rural feeder	15	1,000	704	840	8	4.5	5.5
Typical country short rural feeder	40	1,000	817	1083	8	5.0	6.4
Typical long rural feeder	250	1,400	1,225	1992	10	6.7	10.1

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

The tables below estimates the average number of feeders we expect to exceed the SAIDI or SAIFI levels based on data from 2014-15 to 2018-19 reported by the distributors to the AER. We expect this to be a lower number of feeders compared to the existing standards.

Table 5.6 Non-complying feeders under existing and recommended SAIDI standards

Feeder type	Existing standards		Draft standards		Final standards		Total feeders
	5-year average	% feeders	5-year average	% feeders	5-year average	% feeders	
Ausgrid[a]	**37.8**	**2.2%**	**13.6**	**0.8%**	**10.0**	**0.6%**	**1,731**
Urban	31.8	2.3%	5.4	0.4%	4.2	0.3%	1,366
Short rural	4.4	1.4%	6.6	2.1%	4.4	1.4%	316
Long rural	0.2	4.0%	0.2	4.0%	0.0	0.0%	5
Endeavour	**20.8**	**1.4%**	**11.2**	**0.7%**	**7.0**	**0.5%**	**1,535**
Urban	15.6	1.5%	3.2	0.3%	3.0	0.3%	1,074
Short rural	4.8	1.0%	7.6	1.7%	4.0	0.9%	460
Long rural	0.4	40.0%	0.4	40.0%	0.0	0.0%	1
Essential	**61.0**	**4.2%**	**71.8**	**4.9%**	**30.2**	**2.1%**	**1,461**
Urban	7.2	2.4%	2.4	0.8%	2.4	0.8%	294
Short rural	37.2	4.0%	51.4	5.6%	24.6	2.7%	924
Long rural	16.6	6.8%	18.0	7.4%	3.2	1.3%	243

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

Table 5.7 Non-complying feeders under existing and recommended SAIFI standards

Feeder type	Existing standards		Draft standards		Final standards		Total feeders
	5-year average	% feeders	5-year average	% feeders	5-year average	% feeders	
Ausgrid[a]	**19.4**	**1.1%**	**21.8**	**1.3%**	**20.6**	**1.2%**	**1,731**
Urban	15.8	1.2%	15.0	1.1%	16.0	1.2%	1,366
Short rural	3.4	1.1%	6.8	2.2%	4.6	1.5%	316
Long rural	0.0	0.0%	0.0	0.0%	0.0	0.0%	5
Endeavour	**10.2**	**0.7%**	**19.4**	**1.3%**	**7.0**	**0.5%**	**1,535**
Urban	8.8	0.8%	7.0	0.7%	3.6	0.3%	1,074
Short rural	1.0	0.2%	12.0	2.6%	3.0	0.7%	460
Long rural	0.4	40.0%	0.4	40.0%	0.4	40.0%	1
Essential	**12.0**	**0.8%**	**64.6**	**4.4%**	**21.4**	**1.5%**	**1,461**
Urban	1.4	0.5%	4.8	1.6%	3.6	1.2%	294
Short rural	6.8	0.7%	46.4	5.0%	15.8	1.7%	924
Long rural	3.8	1.6%	13.4	5.5%	2.0	0.8%	243

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

5.4 How should the standards apply to feeders longer than 500 km

In modelling the efficient level of reliability and developing the individual feeder standard formulae we excluded feeders longer than 500 km, as the relationship between feeder length and reliability for these feeders was significantly different to the relationship at shorter feeder lengths. Specifically, the fault rates on the longer feeders were lower, which we expect is due to feeders in arid regions experiencing significantly lower fault rates per kilometre of length.

To subsequently set standards using these formulae would significantly increase (i.e. loosen) the standards for these longer feeders. We consider that an alternative approach is to use a feeder length of 500 km to calculate the standards for all feeders longer than 500 km. This means that the standard for SAIDI would be capped at 2,688 minutes per year and the standard for SAIFI capped at 13.0 interruptions per year. By way of comparison, the longest feeder is around 1,900 km, which would yield a SAIDI standard of almost 5,000 minutes per year and a SAIFI standard of 22.3 interruptions per year under the Final Report formulae.[x]

x Under the Draft Report recommendations this feeder would have a SAIDI standard of 2,740 minutes per year and a SAIFI standard of 13 interruptions per year.

Essential Energy has around 50 feeders longer than 500 km. We estimate that capping the standard at the level of a 500 km feeder would have resulted in an additional 3 of Essential Energy's feeders breaching the SAIDI standard over the period 2014-15 to 2018-19 (i.e. compared to the figures in Table 5.6 above) and no change in performance against the SAIFI standard (compared to the figures in Table 5.7 above).

Final Recommendation

9 For non-CBD feeders that are 500 kilometres or longer, the SAIDI standard should be set at 2688 minutes and the SAIFI standard at 13.0 interruptions. These standards are based on the reliability formulae for other non-CBD feeders and a 'proxy' feeder length of 500 kilometres to recognise the different relationship between feeder length and fault rates for very long feeders.

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

As explained above, we have developed reliability standards for each of the distributors' non-CBD feeders. Ausgrid is the only distributor that has CBD feeders.[y] The nature of the CBD network and its interaction with the transmission network means that there is additional complexity associated with modelling this part of Augrid's network. In our Draft Report, we indicated that we would ask Ausgrid to model the long-term efficient reliability of its CBD network and propose new standards that should apply.

Ausgrid provided additional information on its CBD feeders and proposed maintaining the current standards rather than undertaking further modelling as part of this review.[25] Ausgrid considered that the current CBD reliability standards are fit-for-purpose, for the following reasons:

- The CBD HV network is a unique 'triplex configuration' design, where the majority of distribution substations have 3 transformers, which is significantly different to other parts of the network. This means that any one transformer or feeder could be interrupted or de-energised without affecting supply. The HV distribution system in the CBD is subsequently highly stable, with supply typically only interrupted by rare, unpredictable events.
- Ausgrid does not have any capacity or reliability investment planned for the CBD network in the 2019-24 regulatory period. This means that there is limited scope for Ausgrid to respond to incentives to improve reliability or lower costs.
- Average network reliability on CBD feeders in recent years has been high with only three investigations into feeders that did not meet the standard (and none of these investigations resulted in projects to remediate poor performance). This means that materially increasing or decreasing the SAIDI would be unlikely to have a major impact on network planning and reporting.[26]

y Consistent with our Draft Report, we recommend maintaining the current definition of CBD Feeders to reflect the unique nature of this part of Ausgrid's network. For 'CBD Feeders', the AER has specifically given state jurisdictions the role for determining what constitutes a 'CBD Feeder'. AER, *Distribution Reliability Measures Guideline*, 2018, p 6.

We published Ausgrid's proposal for CBD standards on our website in December 2020 and invited stakeholders to make submissions on it in addition to our Draft Report.[27] PIAC was the only stakeholder to comment on this issue and agreed with Ausgrid's proposal to maintain current standards for CBD feeders, considering that the current network configuration provides ample 'headroom' and the AER's STPIS scheme provides an appropriate control on the reliability experienced by CBD customers.[28]

Our view is that maintaining the current CBD standards would meet the objectives for individual feeder standards set out above – that is to provide a minimum or safety net level of reliability. As noted by Ausgrid, the nature of the CBD network means that any outage is likely to be the result of a rare unpredictable event. When these events occur, the current levels set in the standard trigger an investigation into the causes of the outage and an assessment of the costs and benefits associated with work to improve reliability. Accordingly, we have decided to maintain the current CBD individual feeder reliability standards.[29] The current and proposed CBD individual feeder standards are set out in Table 5.8 below.

Table 5.8 Current and proposed CBD individual feeder standards

	Minutes per customer pa	Number per customer pa
SAIDI individual feeder average reliability duration standard	100	
SAIFI individual feeder standard average reliability interruption standard	-	1.4

Source: Ausgrid Distributor licence under the *Electricity Supply Act 1995 (NSW)*, Schedule 2.

Final Recommendation

10 For CBD feeders (feeders forming part of the triplex 11 kV cable system supplying predominantly commercial high-rise buildings, within the City of Sydney), the SAIDI standard should be set at 100 minutes and the SAIFI standard at 1.4 interruptions. These are the same as the current standards.

5.6 How should we set direct connection standards?

Under the current licences, 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.

We recommend 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 existing levels of SAIFI.

Since we were no longer defining standards by feeder type, there are no equivalent feeder types that we can align the metropolitan and non-metropolitan categories with. Instead, we recommend 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.

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 approach should be retained as it allows for the situation where a customer is receiving a lower level of reliability (at the meter) consistent with the redundancy arrangement that they originally agreed to and paid for.

In response to our Draft Report, Essential Energy agreed with our proposal to set the direct connection standard for all areas using the same formula for SAIDI and SAIFI as for individual feeders but using a 'proxy' feeder length of 1 km.[30] No other stakeholders commented on this issue.

While our formulae for individual feeder standards has changed since the Draft Report the resulting direct connection standards have not changed significantly (see Table 5.9). For SAIDI, the final standard is between the existing metropolitan and non-metropolitan standards for Ausgrid and Endeavour Energy (albeit closer to the metropolitan standard). For SAIFI, the standard is in line with the exiting metropolitan standard (for Ausgrid and Endeavour Energy).

Table 5.9 Direct connection standards

	Draft Report	Final Report
SAIDI	545	530
SAIFI	3.9	4.2

Final Recommendation

11 For direct connections, the SAIDI standard should be set at 530 minutes and the SAIFI standard at 4.2 interruptions. These standards are based on the reliability formula for other non-CBD feeders and a 'proxy' feeder length of 1 kilometre.

5.7 Should the investigation and rectification approach in the existing licences be retained?

We consider that the requirements related to monitoring, investigating and reporting on the reliability of individual feeders that do not meet the standard are broadly 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. The costs and benefits relevant to this analysis include social costs and benefits, rather than just those faced by the distributor (for example, will capture any updates to the AER's value of customer reliability).

Box 5.3 sets out what would be required by the licence when an individual feeder does not meet the standard. In general, distributors with non-compliant feeders are required to identify reasonable solutions that could improve compliance with the standards for those feeders (if they have not already been able to rectify the causes of the non-compliance). The identified solutions must be subject to a cost-benefit analysis. If there is a solution with a positive net benefit then the distributor must implement a solution and must begin no later than 6 months from completion of the investigation report. A distributor is only able to not select a solution if there is no solution that has a positive net benefit.

In response to our Draft Report, both Ausgrid and Essential Energy raised concerns that the effect of our proposed requirements would be to mandate investment in solutions that may be better off not made or deferred.[31] For example, in relation to an individual feeder it may be a better outcome if the distributor can prioritise projects with higher cost-benefit ratios, where deferral would increase the cost-benefit ratio or where safety or bushfire risk requires it not to proceed. We agree that there may be situations where it is preferable to delay or not undertake a project or solution. We have amended the proposed licence condition so that a distributor may not comply with the requirement to invest where the cost-benefit analysis returns a net positive benefit if the distributor can demonstrate to IPART's satisfaction that it would be reasonable not to do so.

Where a distributor seeks approval not to implement a solution, the timeframes under the licence will be put on hold while IPART considers that request. In the event that IPART is not satisfied with the request, the distributor would have the remaining time under the licence to begin implementation of the solution.

Previously the licences have included the absolute levels of the reliability standards. However, for most individual feeder standards, we have decided to express the standard using a formula. While we have not been prescriptive around how the formulae should be applied, we will want to assess whether the distributors are using a consistent approach to calculating the standards and evaluating their performance against them. Accordingly, we offer the following guidance:

- There should be no rounding in the calculation of the standards.
  - The parameters should be used as specified in the formulae we have recommended.
  - If feeder lengths are available to the nearest meter they should be used to calculate the standards (however this is not a specific requirement).
- There should be no rounding of the standards themselves for the purpose of measuring performance against them.
- Performance at or below the standard will be considered compliant.

Final Recommendation

12 For feeders that exceed the standards for SAIDI and/or SAIFI, the distributors should follow a similar reporting and investigation process to the current licence. We recommend that distributors are required to:

- Report on and investigate causes of outages for feeders with reliability that breaches the standard
- Take reasonable steps to improve reliability, develop plans and undertake cost benefit analyses
- Improve reliability where the benefits exceed the costs unless distributors can satisfy IPART that it is reasonable not to do so.
-

Box 5.3 Investigation and rectification of non-conformance with standards

5A.1 (a) Where the *Licence Holder* has exceeded any of the *individual feeder standards* or *direct connection standards* in the 12-month period immediately preceding the end of 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 The *Licence Holder* is not required to implement the *rectification plan* in accordance with condition 5A.4 if, following a cost-benefit analysis in accordance with condition 5A.3:

(a) there are no solutions which demonstrate a positive net benefit; or
(b) the *Licence Holder:*
  (i) demonstrates to the satisfaction of the *Tribunal* that it is reasonable not to implement the *rectification plan*; and
  (ii) has received written confirmation from the *Tribunal* that the *Tribunal* is satisfied that it is reasonable not to implement the *rectification plan*.

5A.6 Where condition 5A.3(b)(ii) applies, the *Licence Holder* must, within one month of that determination, advise the *Tribunal* of the *Licence Holder's* non-conformance with the relevant *individual feeder standards* or *direct connection standards*.

6 Guaranteed customer service levels and payments

Summary of our final decisions

The existing customer service standard should be replaced with a new guaranteed service level (GSL) scheme. The existing scheme is out of date, payments have not increased since 2004 and uptake is extremely low.

We recommend a new GSL scheme that is similar in cost to updating the existing scheme to increase payments by inflation and to increase customer uptake of payments. However, it makes a number of improvements:

- It distinguishes between poor and very poor service, introduces a cumulative outage standard and a consistent approach to exclusions.
- It has higher payments for eligible customers, provision for those payments to increase over time and flexibility to make them using electronic funds transfer.

The minimum levels of reliability and associated payments under the new GSL scheme should be:

GSL	Ausgrid & Endeavour Energy	Essential Energy	Payment
Level 1	20 hours or 10 outages per calendar year	36 hours or 20 outages per calendar year	$120 at 1 July 2024, escalated annually by the change in inflation
Level 2	48 hours or 20 outages per calendar year	120 hours or 50 outages per calendar year	Typical annual distribution network service charge for residential customer

Note: Excluded interruptions are the same as those applying to individual feeder standards.

The scheme should apply to residential and small business customers on the deemed connection contract.

Consistent with the current scheme, if a distributor is unable to meet the standards, they would be obliged to make payment available to that customer on request.

Distributors should take reasonable steps to ensure eligible customers are notified of the scheme. We will monitor uptake of the scheme and direct distributors to take additional steps if necessary.

Specifying a guaranteed service level (GSL) for individual customers is designed to complement the individual feeder standards in the licence. Individual feeder standards focus on the average reliability of a feeder, which could serve anywhere from one to 5,000 customers. This means that a distributor could meet the standard for an individual feeder but still have some customers on it receive a very unreliable supply.

6.1 The existing customer service standard should be replaced with a new GSL scheme

The existing scheme that sets service standards for individual customers has not been updated since 2004 and is in need of modernisation. Under the scheme, customers with poor service are able to apply for an $80 payment from their distributor. Distributors are required to take reasonable steps to notify customers about the scheme but uptake is very low. The key issues with the current customer service scheme are discussed below.

6.1.1 Few eligible customers receive payment under the current scheme

Currently, very few customers receive payments when their service level falls below the specified standard. Across the 3 distributors, around 3% of eligible customers received customer service standard payments in 2019-20 (See Table 6.1).

Table 6.1 2019-20 customer service standard claims and payments

Distributor	Eligible customers	Claims	Payments	% of eligible customers paid
Ausgrid	27,017	3,456	1,548	5.7%
Endeavour Energy	3,434	67	20	0.6%
Essential Energy	17,302	32	8	0.0%
Total	47,753	3,555	1,576	3.3%

Note: The distributors' calculations of how many customers are eligible use different interpretations of the severe weather exclusion. We consider this largely explains the difference between Endeavour Energy and Ausgrid, relative to total customer numbers.

Source: Eligible customer figures supplied by distributors, claims and payments from our Annual Compliance Report – 2019-20, October 2020, p 48.

6.1.2 Payments have not increased for almost 20 years

While payments under the customer service scheme have remained at $80, inflation and energy bills have risen significantly. Since the current scheme was put in place:

- Inflation has risen by 45%[z] - if the payment had been adjusted annually by the change in inflation it would be around $120 now
- Both electricity network tariffs and regulated retail prices have roughly doubled - if the payment had kept pace with network charges it would be around $160 now.[aa]

z This is the December 2020 CPI divided by the June 2004 CPI.
aa This calculation is based on 2019 customer numbers and reported typical usage at the time.

Similarly, the payment has not kept pace with those under similar schemes elsewhere. At the time it was introduced, an $80 payment was also applied by the Victorian Essential Services Commission and the Office of the Tasmanian Economic Regulator.[32] The Victorian GSL will update on 1 July 2021, with multi-tiered payments ranging from $60 to $190.[33]

Combined with the low rate of payment, the low value of the payment means that scheme costs are extremely low for distributors (see Table 6.2).

Table 6.2 Payments made under the existing customer service standard (2019-20)

	Number of payments	Total payments[a]
Ausgrid	1,548	$123,840
Endeavour Energy	20	$1,600
Essential Energy	8	$640
Total	1,576	$126,080

a We have only included the payment costs, not the administrative costs for the distributors.

Note: In 2004, Integral Energy (now Endeavour) estimated it would pay 1,000 to 1,250 customers, EnergyAustralia (now Ausgrid) estimated it would pay 11,000 customers and Australian Inland and Country Energy (now Essential) estimated they would pay around 63,500 customers per year.[34]

Source: IPART, Annual Compliance Report – Energy network operator compliance during 2019-20, October 2020, p 48.

6.1.3 The current scheme may not adequately capture poor service

The existing customer service standards are:

- a single 12-hour or longer outage in metropolitan areas, 18-hour or longer in other areas
- four 4-hour or longer outages in a financial year in metropolitan areas, 5-hour or longer in other areas.[35]

This approach captures only a few ways a customer may receive unreliable service. For example, the distributor does not breach its customer service standard if a customer experiences:

- three 10-hour outages
- 14 outages in a year.[bb]

The Victorian Essential Services Commission and the AER's STPIS both use standards based on cumulative outage duration and total number of outages over the year.[36] These approaches are also conceptually similar to the SAIDI and SAIFI standards we apply to feeder standards.

6.1.4 Exclusions in the current scheme are inconsistent

Currently, customer service standards have different exclusions to the existing individual feeder standards. Having different exclusions adds unnecessary complexity to reporting and

bb As long as all outages shorter than 12 hours and all but three outages shorter than 4-hours.

has no observable benefit to customers. In particular, the current customer service standard has an exclusion for:

> An interruption caused by the effects of a *severe thunderstorm or severe weather* as advised by the Bureau of Meteorology.[37]

Under the current arrangements there is no one correct way to interpret this exclusion. While storm or weather events are listed on the Bureau of Meteorology's Severe Storm Archive, these listed events only record a single town or suburb. Weather warnings often cover a broad area of the state, are frequent and are often cancelled or the severe weather does not eventuate.

We understand that NSW distributors each apply this exclusion differently, with:

- Ausgrid not using it
- Endeavour Energy excluding all outages where a severe weather warning applied from the Bureau of Meteorology
- Essential Energy applying data it receives from a third-party using Bureau of Meteorology data.

Endeavour Energy finds that substantially fewer of its customers are eligible for customer service standard payments than Ausgrid (relative to their customer base), while having relatively similar overall SAIDI performance.[cc] We consider that the differing treatment of exclusions is likely to contribute to this.

6.1.5 The definitions in the current scheme are out of date

In the current scheme, the metropolitan area is defined based on a combination of:

- local government borders – some of these councils have changed borders or been part of amalgamations
- suburb boundaries – there is no official or consistent treatment of suburb boundaries.

This makes it difficult to identify whether some customers are within the metropolitan area. The development of new suburbs has created non-metropolitan enclaves within Sydney.

6.2 The proposed GSL addresses the issues with the existing scheme for a similar cost

We recommend replacing the existing scheme with a two-tier scheme that distinguishes between poor and very poor service, with higher payments for eligible customers, a new cumulative outage standard and a more consistent approach to exclusions. We also recommend some drafting changes to:

- the steps distributors are required to take to notify customers about the scheme

cc In 2019-20 Endeavour Energy (relative to Ausgrid) had 28% lower SAIDI on urban feeders and 65% higher SAIDI on short rural feeders, and 6% lower SAIFI on urban feeders and 32% higher SAIFI on short rural feeders.

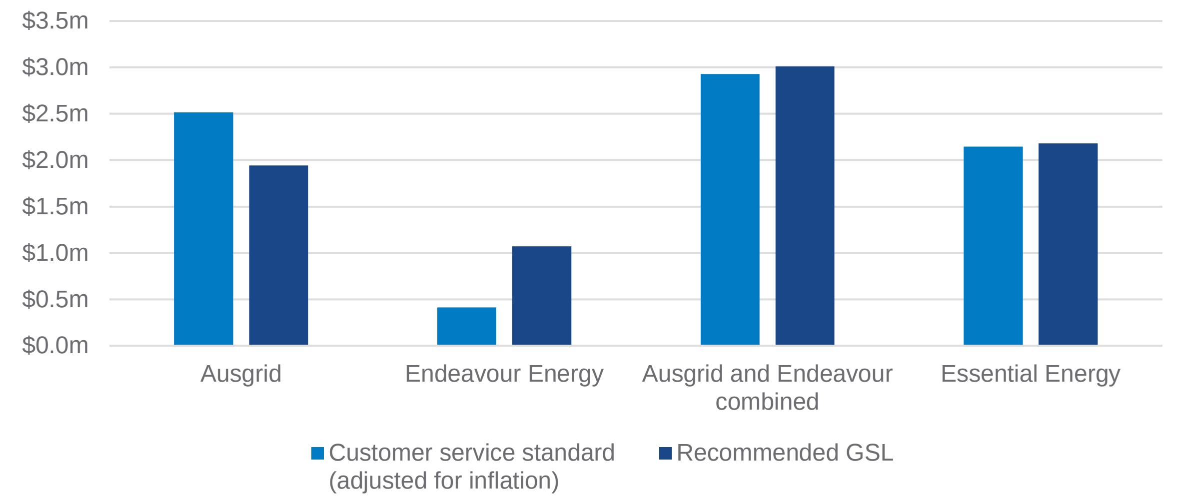
- additional obligations to publish information on uptake
- allow distributors to make payments using electronic funds transfer (EFT) rather than by cheque
- set payments and thresholds by distributor rather than by geographic area.

Each of the changes proposed make the scheme more effective and deliver fairer outcomes for the customers who receive the poorest service. Their purpose is to ensure that the individual customer standards are working as they should and that payments are adequate to acknowledge the poor service delivered.

While the changes we are recommending are consistent with those outlined in our Draft Report, we have amended the thresholds and payment amounts to take into account updated information from the distributors. The updated information showed that the likely cost of the scheme proposed in the Draft Report would be greater than we anticipated, primarily because the thresholds we had proposed would capture significantly more customers than intended. This is discussed in more detail in section 6.4.1 below.

Using the updated information provided by the distributors, we have re-set the thresholds and payments of the proposed GSL scheme in order to keep the overall costs of the scheme at a similar level to the cost of retaining the existing scheme but adjusting the payment to keep pace with the increase in inflation since 2004. We consider that this would minimise the costs of the proposed GSL while still ensuring that the scheme is effective. Figure 6.1 compares the maximum cost of the proposed GSL scheme with the maximum cost of the existing scheme if payments under it were $120 (inflation from 2004 to 2021, plus 1.5% annual inflation to 2024). The estimated increase in Endeavour Energy's costs are due to its interpretation of the 'severe weather' exclusion for the existing customer service standard, discussed in 6.1.4.

Figure 6.1 Comparing potential payments under customer service standard adjusted for inflation with recommended GSL



Note: This graph assumes 100% of eligible customers receive payments for like-for-like comparison purposes.

Data source: Costs of the customer service standard reflect data provided by distributors. We note they applied different interpretations of the severe weather exclusion.

6.2.1 Distributors should take reasonable steps to notify customers

We recommend that distributors take reasonable steps to notify customers that they consider are likely to be eligible for payment under the scheme. We consider that reasonable steps are those based on contemporary communications and costs and are more than the minimum steps noted in the current standards of placing a notice in a newspaper and publishing information on the distributor's website.

Less than 5% of eligible customers receive payment under the current customer service scheme. The low uptake of the current scheme is likely due to the licence conditions that require:

- Distributors to take 'reasonable steps' to make customers aware of the availability of payments while at the same time specifying minimum steps.[dd] This allows distributors to comply with their licence while doing very little to raise awareness. Distributors comply with the condition by taking these steps and in practice take few other steps.
- In 2019-20 most customers that applied for customer service standard payments had their claims rejected.[ee] This combined with the relatively small payment of $80 does not incentivise many customers to apply, particularly given the risk of claims being rejected.

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dd Clause 6.4 of the NSW licences require distributors to "…take reasonable steps to make customers aware of payments [under the GSL]. Reasonable steps include, at a minimum, publication of information on the [distributor's] website and annual newspaper advertisements."

ee According to quarterly performance reports from Endeavour Energy and Essential Energy, most Endeavour Energy claims were excluded either because of severe weather or the outage was not long enough to qualify and most Essential Energy claims were excluded because of natural disaster declarations or the interruption was either not long enough or there weren't 4 eligible outages. Ausgrid does not record its reasons for denying claims in its quarterly performance reporting.

We recommend:

- removing the minimum steps from the NSW licences
- requiring distributors to follow any directions to follow any steps IPART directs distributors to take to inform customers of the GSL and GSL payments.

In our Draft Report we proposed an additional obligation, requiring distributors to provide information on the GSL payments in any information or communications regarding specific interruptions. We have decided not to include that in our final recommendations. Ausgrid and Essential Energy both raised concerns with this proposal.[38] They considered that including information on payments in *any* communications would be expensive.

6.3 The new GSL should apply to residential and small business customers on a deemed standard contract

The existing customer service standard applies to all customers. We recommend that the proposed GSL only applies to residential and small business customers on a deemed standard contract. This is consistent with the approach proposed in our Draft Report.

We consulted on whether the GSL should apply to residential and small business customers on negotiated supply contracts. Very few customers are currently supplied on negotiated agreements but our recommendation will ensure that distributors and customers can negotiate reliability if they want to (for example, in return for a lower price).

Currently it is feasible for large industrial customers (i.e. directly connected customers) to have bespoke/negotiated reliability standards to suit their preferences and/or circumstances. The licence allows the distributors to consider negotiated reliability agreements for these customers when investigating direct connections that do not meet the standards. As technology changes (e.g. battery technology becomes cheaper), distributors may increasingly be able to address reliability issues for individual customers or specific feeders through negotiated outcomes and 'behind the meter' solutions.

In its submission, PIAC supported the opportunities presented by negotiated settlements, however noted that "it is essential any such negotiations are conducted fairly and consumers are not forced (or feel they are forced) to accept such an arrangement against their interests."[39] In discussions with stakeholders, concerns were raised with us that allowing negotiated reliability may lead to customers being taken advantage of and that it would be useful to provide them with guidance as to what kind of trade-offs would be reasonable. We consider that this is an emerging issue. We do not want the licence to prevent distributors and customers from implementing mutually satisfactory arrangements but equally want to ensure that the regulatory regime protects customers where it should.

6.4 Defining service levels and payment for the proposed GSL

For the proposed GSL scheme we decided on a combination of service level and payment that would:

- Trigger payment for customers with the poorest service based on two tiers of service level thresholds.
- For level 1, set the payment of $120 in 2024-25, indexed by inflation in subsequent years.[ff] This is equal to the current customer service standard payment adjusted by inflation since it was first recommended.
- For level 2, set the payment equal to the typical annual distribution service charge paid by residential customers. Currently these are approximately:
  - $150 for Ausgrid and Endeavour Energy.[gg]
  - $340 for Essential Energy.[hh]

The sections below discuss the issues we considered and how we took account of feedback received on our Draft Report in coming to these final recommendations.

6.4.1 Recommended service level thresholds

We consider that the GSL should apply to customers with poor and very poor levels of service. Consistent with the proposed approach in our Draft Report, these tiers reflect approximately 1% of customers with the poorest service for level 1, and approximately 0.1% of customers with the poorest service for level 2. This approach is similar to the Victorian Essential Services Commission's approach to setting its GSL.[ii]

To set the service level thresholds for each distributor, we estimated the outage levels that would capture 1% and 0.1% of the worst served customers. We then made changes to equalise the service levels for Ausgrid and Endeavour Energy so that customers served by similar types of distribution networks have the same GSL service thresholds. We also modified the thresholds to bring those for Essential Energy closer to those for Ausgrid and Endeavour, reducing the difference between the GSL service thresholds in urban and country areas.

Our recommended GSL will lead to fewer customers being eligible for payment under the scheme compared with the existing customer service standard (see Table 6.3).

ff $120 is $80 inflated from June 2004 to March 2021, with annualised 1.5% inflation from March 2021 to June 2024.

gg Based on tariff EA010 for Ausgrid and tariff N70 for Endeavour Energy, inclusive of GST.

hh Based on tariff BLNN2AU, inclusive of GST.

ii The Essential Services Commission defines worst served customers as those who experience approximately the worst 1% of network performance in a year.

Table 6.3 Eligibility for the proposed GSL scheme compared with the current scheme

	Ausgrid	Endeavour Energy	Essential Energy
Current			
Customer service standard	Metropolitan areas: ▼ A single 12-hour outage ▼ Four 4-hour outages Non-metropolitan areas: ▼ A single 18-hour outage ▼ Four 5-hour outages	Metropolitan areas: ▼ A single 12-hour outage ▼ Four 4-hour outages Non-metropolitan areas: ▼ A single 18-hour outage ▼ Four 5-hour outages	▼ A single 18-hour outage ▼ Four 5-hour outages
Eligible customers	1.2%	0.3%	1.9%
Recommended GSL			
GSL1	20 hours or 10 outages	20 hours or 10 outages	36 hours or 20 outages
Eligible customers	0.5%	0.7%	1.7%
GSL2	48 hours or 20 outages	48 hours or 20 outages	120 hours or 50 outages
Eligible customers	0.06%	0.09%	0.10%

Note: The estimates of eligible customers are based on data from 2018-19 and 2019-20 for Ausgrid and Essential Energy. Endeavour Energy was not able to provide data for 2018-19. Ausgrid's performance against the existing standards was significantly worse in 2019-20 than 2018-19, this was not the case for Essential Energy. We do not know whether Endeavour Energy's performance in 2019-20 was typical.

Source: For example, Schedule 5 of Essential Energy's licence.

The service level thresholds in the Final Report are significantly higher than the service level thresholds proposed in the Draft Report, particularly for Essential Energy (see Table 6.4).

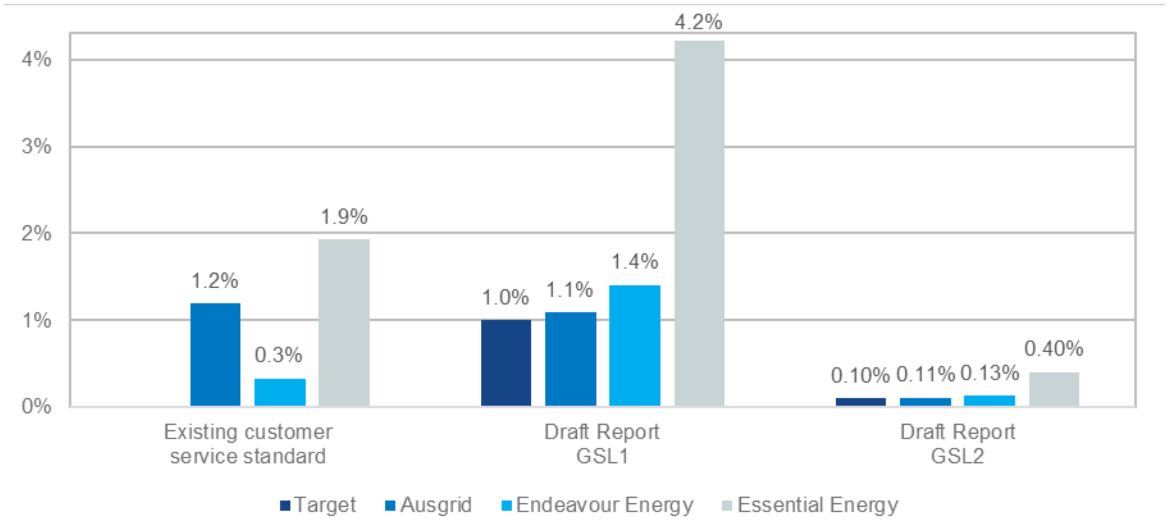
Table 6.4 Recommended service level thresholds compared with the Draft Report

	Ausgrid & Endeavour Energy		Essential Energy	
	Draft Report	**Final Report**	**Draft Report**	**Final Report**
Level 1	15 hours or 8 outages	20 hours or 10 outages	20 hours or 10 outages	36 hours or 20 outages
Level 2	40 hours or 20 outages	48 hours or 20 outages	60 hours or 30 outages	120 hours or 50 outages

The service level thresholds in our Draft Report were designed to capture the 1% and 0.1% of customers with the poorest service. However, in response to the Draft Report, distributors indicated that their own estimates showed that the thresholds in our Draft Report would capture more customers than we had intended.

Introducing a cumulative outage standard required us to estimate the number of customers who would qualify for payment, using the data we had available to us.[jj] Following the Draft Report, each of the 3 distributors provided more information on the cumulative outages experienced by their customers. For Essential Energy in particular, the service level thresholds would have captured a substantially greater proportion of customers than intended (see Figure 6.2 for a comparison of the intended and actual eligibility).

Figure 6.2 Customer eligibility for GSLs (level 1 and 2) under our Draft Report – actual compared with target



Note: The data for Ausgrid and Essential Energy is for 2018-19 and 2019-20. Endeavour Energy was only able to provide data for 2019-20.

Data source: The data is provided by distributors. For the existing customer service standard data, the 3 distributors have used different methods of excluding outages.

6.4.2 Recommended payments

We recommend GSL level 1 payments that are based on applying inflation to the existing $80 payment, bringing it up to $120 in 2024-25 with an inflation adjustment applied in each year. We also recommend GSL level 2 payments that introduce the concept of providing a refund of distribution charges when service is very poor. We recommend that small business and residential customers both receive the same payments under the proposed GSL scheme, as they do under the current customer service scheme. The payments recommended for the Final Report are lower than what we proposed in the Draft Report.

In response to the Draft Report, the distributors submitted that the payments we proposed, which were based on a full year's refund of distribution charges for both level 1 (service charge) and level 2 (usage charge) payments, would be expensive to implement. Distributors noted that the costs of the GSL scheme will be ultimately passed through to all distributors' customers and would result in higher bills.[40]

jj We used publicly available data from the Regulatory Information Notices submitted to the AER.

We reviewed our proposed payments with the aim of providing a better balance between acknowledging those customers who receive very poor service and the costs imposed on customers across the full customer base. The payments recommended in our Final Report will bring the cost of the recommended GSL in line with the cost of inflating the payments under the existing customer service scheme. We consider that is the minimum cost necessary to have a properly functioning and relevant GSL scheme.

We recommend continuing to adopt a payment for level 2 that is based on a refund of distribution charges. This approach reflects that refunds are a common remedy for not meeting contractual conditions. It would also ensure that the payments keep pace with the rate of change in distribution charges, which have been greater than the change in the CPI over the past 20 years. We consider that it is reasonable for the customers who receive very poor service (the worst served 0.1% of customers, approximately), to receive a full refund of their annual distribution service (fixed) charges. To be eligible for this refund, customers need to experience 48 hours of interruption (or 20 individual interruptions) in Ausgrid and Endeavour Energy's network areas for a refund of approximately $150; or 120 hours (or 50 individual interruptions) in Essential Energy's network area for a refund of approximately $340.

To reduce administrative complexity, we recommend setting the payments equal to the annual fixed charge component of distribution charges for residential customers based on the most typical distribution tariff. Under our recommendation, where the distributor does not meet the required service level, a customer is eligible for one level 1 payment and one level 2 payment in each financial year.

Recommendations

13 For residential and small business customers supplied on a deemed standard connection contract, the NSW licences should include a revised guaranteed service level (GSL) scheme. If a distributor is unable to meet the GSL standards for a particular customer, then they should be obliged to make payment available to that customer on request. The GSL should specify the minimum levels of reliability and associated payments set out in the table below:

GSL	Ausgrid & Endeavour Energy	Essential Energy	Payment
Level 1	20 hours or 10 outages per calendar year	36 hours or 20 outages per calendar year	$120 at 1 July 2024, escalated annually by the change in inflation
Level 2	48 hours or 20 outages per calendar year	120 hours or 50 outages per calendar year	Typical annual distribution network service charge for residential customer

Note: Excluded interruptions are the same as those applying to individual feeder standards.

6.5 Payment should continue to be available on application

We consider that payments should remain by customer application, consistent with the proposed approach in our Draft Report. We recommend that distributors continue to be obliged to take reasonable steps to notify customers of eligibility thresholds and payments under the scheme.

There was some stakeholder support for automating payments so that all eligible customers would receive a payment.[41] Distributors noted that automatic payments are technically difficult. Automatic payments would require greater network visibility, as distributors do not currently receive automated information about network outages or know which customers' supply is interrupted. Automatic payments may also be administratively complex because customers' primary billing relationship is with their retailer, not their distributor. Therefore distributors would need to either find a way to pay customers directly, or pay them through their retailer. Without a change to the NSW National Energy Retail Law there would be no requirement for retailers to pass on these payments to customers.

More information on our recommendations around the customer notification requirements are set out below.

6.5.1 Distributors should publish data on GSL performance

To assess whether the steps to inform eligible customers are effective, we need to understand the proportion of eligible customers receiving GSL payments. Under the current licences distributors report only on how many customers apply and how many customers receive customer service standard payments. This information is insufficient for IPART to assess whether distributors are taking reasonable steps to inform eligible customers.

We recommend that distributors are required to publish their best estimates of how many customers received worse service than each GSL level. This information will help IPART assess whether distributors are taking reasonable and effective steps to inform customers that they are eligible for GSL payments. This recommendation is consistent with our Draft Report.

We expect to see an uplift in the number of customers being paid under the proposed GSL scheme compared with the current scheme. If there is no increase in the customers applying for the scheme we may impose additional requirements on distributors to notify customers about the scheme.

6.5.2 Distributors must take all reasonable steps to pay eligible customers that claim GSL payments within 12 weeks

Most distributors currently make GSL payments by cheque to the small number of customers who apply and are eligible. This is expensive, and may not be sustainable for distributors if there is a significant increase in GSL payments. Very few customers handle cheques these days and they are expensive and inconvenient for customers to bank, reducing the value of the payment received. It is in the interests of both distributors and customers to move to electronic funds transfer (EFT) to make these payments.

Ausgrid commented that moving to EFT payments is complicated by the requirement that they 'must' make payments.[42] Ausgrid is concerned that under the current wording of the licence the distributor would not be compliant where it had contacted a customer and requested EFT payment details but had not received them. Issuing a cheque is a simpler way for a distributor to ensure that they can meet this obligation. In response to our draft licence conditions, Ausgrid proposed replacing the obligation that:

> 6.6 The *Licence Holder* must:
>
> (a) make a *GSL payment* to an Eligible Customer …
>
> (b) within three months of date of the application, pay an Eligible Customer…

With:

> 6.6 The *Licence Holder* must take all reasonable steps:
>
> (a) to make a *GSL payment* to an Eligible Customer …
>
> (b) within three months of date of the application, to pay an Eligible Customer…

We agree with this suggestion. We also consider that in order to meet their obligation to take reasonable steps, distributors would need to offer a range of low cost payment methods, where possible, and to inform their customers of payment options and what information is required for customers to receive payments.

In our Draft Report, we proposed to require distributors to make a decision on whether the customer was entitled to a payment (and inform customers of that decision) within one month and make payment within 3 months of an application. Ausgrid found that from a customer's perspective, these timeframes could be confusing. We agree and recommend applying a single 12-week timeframe, as Ausgrid suggested. We encourage distributors to make payments as soon as possible.

Recommendations

14 Under the proposed GSL scheme, the distributors should be required to:

- take reasonable steps to ensure eligible customers are aware of the scheme and follow any directions provided by IPART to take specific steps towards informing eligible customers
- report on the steps they have taken, how many customers were eligible, how many customers applied for payments and how many customers received payments
- take all reasonable steps to pay eligible customers within 12 weeks of receiving an application.

7 Distributed energy resources (DER)

Summary of our final decisions

The current regulatory framework should change to better incentivise distributors to invest efficiently in DER hosting capacity:

- The national framework focuses on minimising expenditure
- There is limited public awareness of DER connections and constraints
  - This inhibits distributors in planning and managing supply, and customers in making efficient DER investment decisions.

Distributors' licences should include a DER information disclosure requirement commencing in 2024-25:

- An information requirement addresses the lack of visibility about DER penetration with minimal regulatory burden on distributors
- Implementing a new GSL standard to compensate DER customers who receive below-threshold network access to export DER electricity would be premature in light of ongoing national reforms.

Information should be reported by distributors voluntarily, using their 'best endeavours' until 2024:

- This gives distributors flexibility to implement systems for capturing this information from 1 July 2021 until their licence is updated in 2024.

Our recommendations provide a balance between awaiting outcomes from concurrent national processes and regulating DER through licence conditions:

- We have aligned our definitions and reporting requirements with the latest available information from national reform processes, including AEMO's DER register.

We will review the requirements in our Reliability Reporting Manual as required, to accommodate changes in national requirements to avoid duplication.

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 can include:

- 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
- 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 who may be experiencing lengthy and frequent outages.

However, because the distribution networks were not designed originally 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 whether 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 being able 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 distributors' licences could be used to create those incentives
- how any such reliability standards would interact with national reliability incentives.

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 feedback and processes underway at the national level relating to efficiently integrating DER into the energy market (see Appendix C).

7.1 There are insufficient incentives for 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.[kk][43] The concept of minimising expenditure does not include making the most efficient investment decisions to resolve the network issues caused by DER.

Based on consultation with the distributors, HoustonKemp found that the distributors have:

- **Limited awareness of DER connections**. This awareness is limited to connection applications, although the introduction of AEMO's DER register has improved this awareness (discussed in section 7.3 below).
- **Limited visibility of DER constraints on their network**. Distributors 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.[44]

These limitations mean distributors are unable to estimate the amount of DER exported 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.[45] 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.[46] This has negative consequences for solar customers and suppliers, who do not have enough, consistent information from Essential Energy on which to base their business decisions.[47]

Ausgrid and Endeavour Energy have fewer DER constraints issues, and still rely solely on inverters to manage these issues. None of the distributors have visibility of when these inverters trip.[48]

Endeavour Energy indicated that it currently schedules minor works to boost hosting capacity.[49] However, this may not be sustainable as DER uptake increases because the need to boost hosting capacity will also increase.

These findings demonstrate the need for regulation of DER to ensure distributors can invest in adequate hosting capacity.

kk HoustonKemp Economists considered that this was evident through issues such as the absence of a minimum service standard for hosting capacity.

7.2 Reliability standards could be used to create those incentives

HoustonKemp analysed several regulatory options to create incentives for the distributors to increase hosting capacity for customers, including 2 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.[ll]

We do not consider that introducing a new guaranteed customer service standard, to 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.

Introducing an information disclosure requirement is a more prudent starting point for 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. Such information would also be valuable in determining the necessary amount of regulation of DER and to inform customer decisions on investing in DER.

Stakeholders agreed that networks should be responsive to technological change and generally supported our DER information reporting requirements. However, they expressed concern that:

- distributors have limited visibility of the low voltage network at a customer's connection point[50] and that information is unreliable at present[51]
- some of our information requirements capture factors outside the networks' control, such as weather, upstream limitation or customer load control agreements with third parties[52]
- the costs of meeting reporting requirements may exceed the benefits to customers[53]
- our proposed definitions were not clear and consistent with national conventions.[54]

Distributors expressed their willingness to work towards providing the requested information on a 'best endeavours' basis until 2024. They requested that we avoid locking in any compliance requirements in favour of a more responsive approach to each DNSP's capabilities, such as adjusting the Reliability Reporting Manual to ensure flexibility.[55]

[ll] As HoustonKemp Economists was engaged before national DER-related reforms were initiated, it also considered four options that would need to be effected 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.

In response to this feedback we have clarified some of our definitions and made some small amendments to the scope of reporting in our Reliability Reporting Manual since the Draft Report.

7.2.1 We have added a glossary to our Reliability Reporting Manual

In response to stakeholder feedback we have amended our definition of DER in the Reliability Reporting Manual as follows:

> DER means distributed energy resources comprising small generating units and generating systems located on the customer's side of the metering installation that export electricity into the Licence Holder's distribution network. For the purpose of this reporting manual, it excludes electric vehicles and their charging infrastructure.

Our intention is to capture information only pertaining to small generating units as defined by the National Electricity Rules (NER). We propose to exclude electric vehicles and their charging infrastructure at this time, due to the complexity of accurate reporting. Customers can use and charge electric vehicles across network boundaries without a distributor's knowledge. It may not require any modifications to a customer's connection and distributors may not be informed of the appliance triggering the change if it did.[56]

We have added a glossary of other relevant terms, ensuring consistency with the NER and adopting conventions used by other national DER regulatory bodies such as the AER, AEMC and AEMO where applicable. We will continue to monitor national developments and consult with distributors to refine our reporting requirements until the new licence comes into effect in 2024.

7.2.2 We have revised the scope of our reporting requirements

We have removed our draft requirement to report on the volume of electricity that could not be produced by a DER system due to insufficient hosting capacity.

Distributors submitted that this would be a difficult measure on which to provide accurate information without sufficient saturation of smart meters.[57] Given the difficulty in providing accurate information, we consider that it is unlikely to contribute meaningfully to network and customer incentives to invest efficiently in DER and DER hosting capacity at this time.

We have also amended our reporting requirement on the number of customers that are subject to static limits or who are refused connection to the distribution network due to DER constraints. Distributors noted that under the NER, they cannot refuse to connect a customer. However, they could impose export limits to prevent power quality issues, which is already covered in our requirements.

Box 7.1 summarises our information requirements.

Box 7.1 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 in the Reliability Reporting Manual[a]:

- the number of DER customers connected to the Licence Holder's distribution network
- the volume of electricity exported into the Licence Holder's distribution network from DER
- the top 10 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 number of complaints from DER customers by 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 on 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
- the number of DER customers that are actively being curtailed from exporting some electricity via a partial static limit
- 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 reasons for expenditure options).

a The Reliability Reporting Manual is available on the IPART website.

7.2.3 Implementation should be voluntary, with distributors using their 'best endeavours' to provide the information until 2024

Distributors expressed concern about meeting our reporting requirements in the short-term.[58] We request that distributors begin reporting this information from 1 July 2021 voluntarily, using their best endeavours to provide the information sought. We will issue a revised Reliability Reporting Manual to give effect to this requirement from 1 July 2021.

We will monitor national developments and continue to consult with distributors until the new licence conditions come into effect in 2024. This provides more information to DER customers immediately but gives distributors time and flexibility to implement systems for capturing this information before it becomes part of their licence conditions.

Recommendation

15 The NSW licences should require distributors to publish information on distributed energy resources (DER) on a quarterly basis. This would provide more data about the impact of export constraints on customers and inform future decisions. We will amend the current Reliability Reporting Manual to include a request for distributors to disclose this information on a voluntary basis until the new licence commences in 2024.

7.3 We will monitor the interaction between licence requirements and national incentives

Our information disclosure requirement complements the DER register AEMO introduced in May 2020.[59] This register stores information about DER devices installed on-site at residential or business locations. The visibility of installed DER devices allows AEMO to better manage the electricity grid and ensure reliable, secure and affordable energy. 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).

The intent of our information disclosure requirement is similar to that of the DER register, in that it increases visibility of installed DER devices. 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.

On 25 March 2021, the AEMC published a Draft Rule Determination on access, pricing and incentive arrangements for DER.[60] The draft rule proposes to:

- update the regulatory framework to clarify that distribution services are two-way and include export services
- encourage distributors to deliver export services that customers value through allowing for financial penalties and rewards for network service quality, and
- allow distributors to offer two-way pricing for export services, and pricing options that suit their capability, customer preferences and jurisdictional policies.

In particular, the draft rule requires the AER to:

- review the service target performance incentive scheme (STPIS) with the view to extending it to export services (by 31 December 2022)
- develop a method to regularly calculate the customer export curtailment values (CECV), which will be used to guide efficient network planning, investment and regulatory decisions (by 1 July 2022)
- develop and publish export tariff guidelines (by 1 July 2022).

The draft rule incorporates provisions allowing distributors at least 12 months before they need to report new information in their Distribution Annual Planning Reports. It allows flexibility for jurisdictional authorities to set service standards covering the performance of export service that better meet the jurisdictional circumstances.

The AEMC is consulting on its Draft Rule Determination and intends to publish its final determination by the end of June 2021.

Under these timeframes, it would be 2023 before distributors are subject to new national incentives and reporting requirements. Incorporating a DER information requirement now strikes a good balance between awaiting outcomes from national processes (which may take some time to finalise), and prematurely regulating DER through the licence conditions. We will continue to monitor the AER's progress in implementing its work program, as well as other national reforms, to ensure that our requirements are not duplicative and to determine whether any additional regulation is required through the licence conditions.

8 Standalone power systems (SAPS)

Summary of our final decisions

SAPS are not currently covered by the distributors' operating licences or the national regulatory regime:

- However, the Australian Energy Market Commission (AEMC) has developed a national regulatory framework (i.e. law and rule changes) for distributor-led SAPS, which is expected to be implemented before the new reliability standards commence
- The NSW Government will also need to amend the state's regulatory framework to incorporate distributor-led SAPS.

Customers connected to distributor-led SAPS should receive the same customer protections afforded by the licence as other customers of the distributors.

The NSW licence conditions should set the following reliability standards for customers supplied by a distributor-led SAPS:

- individual feeder standards apply to microgrids with HV distribution lines
- individual feeder standards with a default length of 200 km apply to all other SAPS
- GSLs and GSL payments apply to all SAPS customers consistent with how they apply to grid connected customers
- provision for SAPS that do not meet the reliability standards at the point of measurement but otherwise deliver the required level of service to the end-customer (e.g. through a behind the meter solution) to be considered compliant with the standards.

Our terms of reference require us to have regard to changes in the licence that would assist the distributors to evolve and take advantage of new technologies, such as SAPS, which may offer more cost-effective solutions than traditional network investment. A SAPS is any system that is not connected to the NEM's interconnected grid and generates a supply of electricity for customers. This chapter discusses the types of SAPS that are used by distributors, the legislative framework and how we consider the reliability conditions in the licence should apply to distributor-led SAPS in the future.

8.1 What types of SAPS do our recommendations apply to?

Our recommendations apply to SAPS that are operated by or on behalf of the distributors. Other parties may also own and operate SAPS independent of one of the distributors – these are referred to as third-party SAPS and are not covered by the reliability standards in the NSW distribution licences.

There are two main categories of SAPS:

- **Microgrids** that supply multiple customers.[61] This covers a wide range of possibilities, e.g. providing electricity to:
  - as few as 2 premises
  - as many as a large town (e.g. the Mount Isa-Cloncurry network is sometimes referred to as a microgrid[62] and it supplies over 10,000 customers with generation primarily from a gas fired power plant).
- **Individual power systems** that supply a single customer.[63] These systems are likely to be the most common type of SAPS. Typically, an individual power system will be installed on the customers' property.

Whilst distributor-led SAPs are not common in NSW, we expect their use to expand as the legislative frameworks are updated to accommodate their use (see section 8.2 below) and new technology improves their efficiency and competitiveness with the traditional network infrastructure.

There are 3 reasons why distributors may seek to employ SAPS:

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

Essential Energy trialled the use of SAPS as an emergency response tool during the 2019-20 bushfire season (see Box 8.1) and is currently investigating where SAPS could provide electricity to customers instead of through the traditional poles and wires network.[64] In its submission to the Draft Report, Essential Energy noted that approximately 0.5% of its customers require around 17% of its network length to service their electrical needs. Essential Energy considers that the use of SAPS for 'edge of grid' customers not only improves reliability for those customers but also reduces network costs for other customers. Essential Energy further contends that larger scale deployment of SAPS has the potential to:

- Improve the reliability of supply to customers in challenging environments or at the edge of the grid.
- Reduce the costs to maintain Essential Energy's network and therefore reduce network charges for all customers.[mm]
- Reduce bushfire risk. Significant parts of Essential Energy's infrastructure are located in high risk bushfire areas. The risk that energised powerlines could cause a spark which may ignite a bushfire is removed with a SAPS.
- Embed resilience in the network, enabling a customer or community to isolate itself and remain energised in an emergency. This is particularly important for keeping telecommunication towers and fire-fighting equipment operational.
- Be modular and easily transportable, making SAPS especially suited to emergency response situations.[65]

The NSW distributors estimate that they could supply over 2,000 customers via SAPS by 2030, mostly in the Essential Energy footprint.[66]

[mm] These savings are driven by reduced operational costs (such as vegetation management around infrastructure) and the ability to remove sections of the network that traverse through difficult terrain and serve few customers.

Box 8.1 Essential Energy's Peak Alone SAPS

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

- one 12 kilowatt (kW) solar array
- one 4kW solar array
- six 13.5 kilowatt-hour (kWh)/Total 81 kWh batteries (Tesla Powerwall 2)
- two 13.5kWh/ Total 27 kWh batteries (Tesla Powerwall 2)
- 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 4.1 km 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.

8.2 What is the legislative framework for SAPs in NSW?

The existing regulatory frameworks for the distributors exclude SAPS. The NSW distributors are primarily regulated by the:

- *National Electricity Law* and *National Energy Retail Law* and their associated rules and regulations
- *Electricity Supply Act 1995 (NSW)* and its associated regulations and licences.

The *National Electricity Rules* under the *National Electricity Law* regulate the activities of the distributors and restrict the extent to which they can be involved in electricity generation and the sale of electricity to customers (i.e. electricity retailing). Thus a SAPS provided by a distributor falls outside this framework and legislative amendments are required to incorporate these SAPS into the frameworks applying to the NSW distributors.

The AEMC has proposed law and rule changes that will accommodate both distributor-led and third-party SAPS.[67] We understand that the NSW Department of Planning, Industry and Environment (DPIE) is currently considering amendments to NSW legislation that would incorporate distributor-led SAPS into the distributor licensing framework. While the timing of these changes is unclear, we have made our final recommendations with the expectation that this will happen by 2024, when our recommended licence amendments would apply. We recommend that the NSW Government progress the required changes within the national framework and at the state level.

Essential Energy supports this position and requested that IPART recommend that the NSW Government opts in "to the national SAPS framework and derogations for activities that are providing suboptimal customer impacts".[68] In particular, Essential Energy wants the ability to undertake fault and emergency responses for SAPS. Once the AEMC's framework is implemented, we agree that NSW should opt in to it. In terms of a derogation to allow distributors to undertake fault and emergency response, we understand that DPIE will soon begin consulting on specific derogations. We will support this process by engaging and making submissions as appropriate.

The Clean Energy Council requested that IPART support universal access to dispute resolution for SAPS customers.[69] Currently the NSW version of the *National Energy Retail Law* and *National Energy Retail Regulations* only apply to customers supplied via the 'interconnected national electricity system. Therefore, customers who move off-grid would lose their energy-specific consumer protections under the *National Energy Customer Framework* (NECF). We expect that amending NSW regulations and legislation to include distributor-led SAPS will mean that customers moved to a SAPS will maintain their existing consumer protections, including dispute resolution, and lead to their coverage by NECF more generally.

Recommendation

16 Recognising the growing importance of distributor-led standalone power systems (SAPS), the NSW Government should continue to progress legislative changes to incorporate them within both the:

– NSW Electricity Supply Act framework

– National Energy Retail Law (New South Wales), on implementation of the AEMC's proposed legal and regulatory framework.

8.3 How should the distribution licences treat SAPS?

As the timing and form of legislative changes to accommodate in SAPS in the regulatory framework is uncertain, we are unable to make precise recommendations as to the form that SAPS licence conditions should take. However, there is good reason for providing guidance on the reliability standards that should apply when legislative reform to incorporate distributor-led SAPS occurs. We consider that customer protection is important as distributors can move customers from the network to a SAPS without explicit consent.[nn]

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 that protects customers' interests.

nn 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).

Our final recommendation for grid-connected customers (see Chapter 3) is to continue to set reliability standards for:

- individual feeders
- GSLs and associated payments.

We recommend that reliability standards also extend to distributor-led SAPS, so that these customers have the same regulatory protections (with regard to supply reliability) as if they were supplied from the grid. Our 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[70] and received broad support from stakeholders.[71]

We also consider that provision should be made for SAPS that do not meet the reliability standards at the point of measurement but otherwise deliver the required level of service to the end-customer (e.g. through a behind the meter solution) to be considered compliant with the standards.

8.3.1 Extending the individual feeder standards to distributor-led SAPS

We recommend applying the individual feeder standards to SAPS. This will require some changes to the licence when the AEMC's framework for distributor-led SAPS is implemented. How we recommend applying the individual feeder standard depends on the characteristics of the SAPS:

- Some large microgrids will have HV power lines that resemble feeders. We recommend that individual feeder standards should apply to these HV power lines as if they are feeders.[oo]
- Where SAPS replace the need for long feeders (either through an LV microgrid or an individual power system) we recommend setting the default SAIDI and SAIFI for SAPS equal to the standards for a 200 km feeder.

Essential Energy requested that we provide clarification around extending the individual feeder standards to SAPS.[72] Our intention is that if a microgrid operates like a mini-network and has feeders (e.g. the Mount Isa-Cloncurry network), then the individual feeder standards should apply based on the feeder lengths within the microgrid. Where an LV microgrid or an individual power system replaces the need for long feeders, then SAIDI and SAIFI should apply to these SAPS equal to the standards for a 200 km feeder. Microgrids that connect and disconnect from the NEM should be treated as NEM-connected feeders.

In its submission to the Draft Report, PIAC recommended that a customer who has been transitioned to a SAPS should have a reliability standard based on the actual feeder length they used to be supplied by.[73] PIAC considered this to be more in line with the principle that the customer should see no change in their protections, rather than being defaulted to a 200 km feeder as proposed by IPART.

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oo 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.

We proposed using a default feeder length of 200 km for setting SAPS reliability standards as it is the current threshold for defining a 'long rural feeder', which SAPS are most likely to replace or substitute. We recommend maintaining the 200 km default feeder length for setting the reliability standard for SAPS for two key reasons:

- It is preferable to have the same reliability standard for all customers connected to distributor-led SAPS. In theory the SAPS market will be competitive. We consider that applying the same reliability standard for all SAPS is more likely to facilitate entry into this market than bespoke arrangements for each individual SAPS.
- While PIAC's proposal to use the existing feeder length is workable for existing customers who move or are moved to a SAPS,[pp] it provides no guidance on how to set reliability standards for new customers. While we cannot know the extent to which SAPS may or may not be used to supply new customers, we consider it is important to establish a regime that accommodates SAPS for both existing and new customers, and on an equal basis.[qq]

8.3.2 Applying the guaranteed service levels and payments 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 final recommendation (for grid connected customers – see Chapter 6) is to replace these with guaranteed service levels and payments consisting of 2 levels (i.e. 2 thresholds of reliability performance that trigger different payments), changing the way the payment is calculated and applying them to residential and small business customers on the deemed standard connection contract.

At this stage it is unclear if the proposed legislative changes to accommodate SAPS intend for the SAPS customers to typically be covered by the deemed standard connection contract, or whether they will be expected to enter negotiated contracts. We also understand that some SAPS customers (such as businesses with specific electricity needs) may prefer to enter a negotiated contract with their distributor to negotiate price and reliability, with supply tailored to their requirements. However, in principle, we see no reason why either the standards or the payments should differ for SAPS customers and we recommend that they be applied in the same way as for grid-connected customers.

pp Although we note the standards themselves would change in line with the changes we recommend setting individual feeder standards. Using the threshold for the long rural feeder effectively produces the most stringent standard that would have been set for these types of feeders (i.e. the lowest SAIDI and SAIFI, as they are a function of length).

qq Anecdotally, we understand that a SAPS can provide a higher level of reliability than grid connection, so we expect that some new customers would choose to be supplied by one.

8.3.3 Assessing when SAPS comply with the standards

Endeavour Energy considered that the NSW licences should accommodate circumstances where SAPS customers agree bespoke reliability standards and/or acknowledge the role customers can play when considering corrective actions.[74] Essential Energy highlighted that there may be circumstances where the reliability performance of a SAPS is outside the ability of the distributor to improve, for example, the failure of a customer to refill the backup diesel generator causing an extended outage.[75]

While we do not know what the final contracting arrangements for customers of distributor-led SAPS will look like, we expect that any arrangement will specify the ongoing rights and responsibilities of both the distributor and customer.

Currently, it is feasible for large industrial customers (i.e. direct connection customers) to have bespoke or negotiated arrangements to suit their preferences and/or circumstances. The licence allows distributors to consider these arrangements when investigating direct connections that do not meet the reliability standards. We recommend retaining this licence condition, as it allows for the situation where a customer is receiving a lower level of reliability consistent with the arrangements that they originally agreed to and paid for.

As technology changes (e.g. battery technology becomes less costly), distributors may increasingly be able to address reliability issues through negotiated outcomes and 'behind the meter' solutions. We do not want the licence to prevent distributors from implementing cost-effective solutions via SAPS that deliver the level of service required, even if it does not satisfy the reliability standards as measured at the meter.

We recommend that, once legislative amendments are made to incorporate distributor-led SAPS into the distributor licensing framework, the SAPS should be deemed to be compliant with the reliability standards where they do not meet the reliability standards at the point of measurement, but deliver the required level of service to the end-customer.

Recommendation

17 The NSW Government should ensure that legislative changes provide customers of distributor-led SAPS with the same protections afforded to grid connected customers. On commencement of those legislative changes, the NSW reliability standards should be extended to distributor-led SAPS as follows:

- – For microgrids with feeder-like high voltage distribution lines – the individual feeder standards should be set consistent with other non-CBD feeders (using the reliability formulas set out in recommendations 8 and 9).
- – For all other distributor-led SAPS – the minimum level of SAIDI should be set at 1817 minutes and the minimum level of SAIFI at 9.4 interruptions. These standards are based on the reliability formula for other non-CBD feeders and a 'proxy' feeder length of 200 km in line with the current threshold for defining a long rural feeder.
- – For customers supplied by distributor-led SAPS, the GSL scheme should apply as if those customers were connected to the grid.

– Where SAPS do not meet the reliability standards at the point of measurement but deliver the required level of service to the end-customer, the SAPS should be deemed to be compliant with the reliability standards.

9 Commencement, compliance and further reviews

Summary of our final decisions

The new standards will come into force on 1 July 2024:

- This aligns with the beginning of the next regulatory period for distributors
- However, the DER information disclosure should commence from 1 July 2021 on a voluntary basis
  - This provides an incentive for distributors to develop their information gathering systems, without penalising them for failing to meet requirements.

DNSPs should provide annual compliance reports to IPART to determine the frequency and scope of audits based on reliability performance:

- This reduces the burden of the current requirements, which are to provide quarterly compliance reports and annual independent audits.

DNSPs should maintain their quarterly investigations of individual feeder SAIDI and SAIFI performance, and report outcomes to IPART annually:

- IPART will retain the discretion to determine the frequency and scope of independent compliance audits
  - We propose to use a risk-based approach, which would reduce regulatory costs for distributors.

The reliability standards should be reviewed every 5 years:

- This provides time for distributors to incorporate standards into their processes and allows the standards review to inform the regulatory review.

We propose to review our Reliability Reporting Manual requirements as required, in response to changes in the national regulatory framework.

The final step in our approach is to establish the compliance and monitoring framework for the reliability standards. This includes:

- when the new standards should take effect
- how often distributors should be required to report against the standards
- how these reports should be audited
- when the standards should be reviewed and who is best placed to conduct future reviews.

This chapter explains our final recommendations on these topics.

9.1 The licence conditions should apply from 1 July 2024

We recommend that the licence conditions apply 1 July 2024, which is the start of the next revenue determination period. This commencement date gives 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.

9.1.1 Distributors should provide DER information voluntarily from 1 July 2021

We consider that there are benefits to distributors reporting publicly on DER earlier than 2024. This would help customers make decisions about investing in DER and allow distributors time to implement systems for gathering this information before their licences are renewed in 2024. We have made this requirement voluntary, with distributors to use their best endeavours to provide the information until then (see Chapter 7).

Recommendation

18 The revised licence conditions should come into force on 1 July 2024.

9.2 Distributors should report their compliance to IPART annually

Self-reporting and independent audits are important features of a compliance regime. IPART maintains a Reliability Reporting Manual, which sets out detailed reporting requirements, including the timing of reports. The licence conditions allow the Tribunal to adjust the timing of reporting requirements through its Reliability Reporting Manual if it finds cause for more or less frequent reporting.

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. 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.

Historically, distributors have demonstrated a high level of compliance with current reliability conditions.[76] As such, we consider that a shift from quarterly to annual reporting is a low risk change that reduces the reporting burden on distributors.

Stakeholders supported this change and considered it would increase distributors' engagement with the reporting process.[77]

However, we recommend that distributors should publish DER information quarterly to provide customers with up-to-date information on which to base their DER investment decisions.

Recommendation

19 Distributors should be required to provide annual reports to IPART on their compliance with reliability standards, with flexibility for IPART to adjust report timing and frequency through the Reliability Reporting Manual.

9.2.1 Distributors should continue to undertake quarterly investigations

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

The investigative requirement is valuable to ensure the timely identification of underperforming feeders and potential rectification to provide better customer outcomes. However, the outcomes should be reported to IPART annually rather than quarterly. We propose to amend the frequency of this reporting through the Reliability Reporting Manual.

Recommendation

20 The distributors should 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.

9.2.2 IPART should have discretion regarding audit frequency and scope

We apply a similar risk-based approach to compliance auditing (where legalisation allows). In recent years, the annual audits have not highlighted any issues of significant concern.

The current licence conditions require an annual independent, 'limited assurance' audit. We consider it is more appropriate to provide the Tribunal with the discretion to call for an independent audit with a tailored audit scope as needed. 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 3 distributors based on their circumstances, compliance history and behaviour. We expect this will lead to a reduction in regulatory cost for the distributors.

Recommendation

21 The NSW licence should allow IPART, as the licence administrator, the discretion to determine the frequency and scope of independent compliance audits, using a risk-based approach.

9.3 IPART should have flexibility to review the standards periodically

We recommend reviewing the final standards periodically for several reasons:

- 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 this data is now used to establish reliability standards.
- To adapt to new legislation and technology, which is particularly likely for SAPS. There is merit in ensuring the standards remain relevant, efficient and effective.
- The method we adopted is innovative and is likely to benefit from development over time.

Reviews 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. We recommend completing the first review by June 2027.

Reviews should occur on a 5-yearly basis thereafter. This provides a good balance between providing time for distributors to incorporate standards into their processes, limiting regulatory burden, and achieving the best outcomes for consumers. It also aligns with the AER revenue determination timing. Stakeholders supported a 5-yearly review.[78]

As licence administrator under the *Electricity Supply Act 1995*, IPART is required to report to the Minister on a 5-yearly basis with its view on whether to conduct a review of licence conditions.[79] This provides a suitable mechanism for IPART to trigger reviews of the reliability standards. As part of licence reviews, IPART intends to consider the adequacy of the reliability licence conditions by June 2027, and subsequent reviews 5-yearly thereafter.

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

This appendix provides 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.1Figure 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.[80]

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.[81] While historically the distributors have provided a high level of reliability, analysis by the Reliability Panel shows that 94% of interruptions to customer supply (both planned and unplanned) in the past decade were caused by distribution network outages.[82]

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[83]
- Essential Energy distributes electricity to the remaining 95% of NSW and some parts of Southern Queensland.

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.[84] 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.[85] 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 4 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[rr] (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.

[rr] 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.1 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 IPART's website.

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)

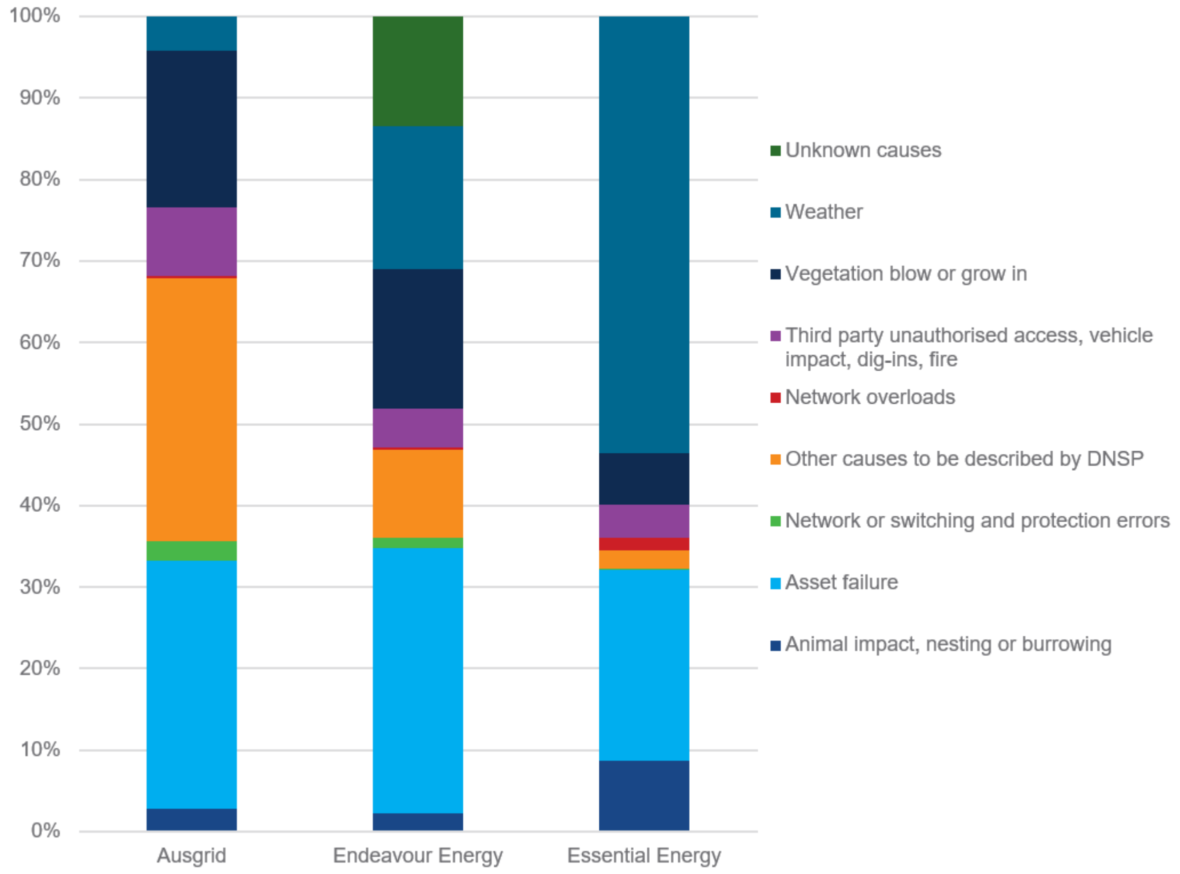
Feeder type	Ausgrid	Endeavour Energy	Essential Energy
CBD Sydney	1.4	N/A	N/A
Urban	4	4	6
Short - rural	8	8	8
Long - rural	10	10	10

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 5 hours

Unplanned outages on a distribution network can occur for several reasons. Some factors can be directly influenced by the distributor (e.g. equipment failure due to age or condition) while others are outside of the distributor's control (e.g. outages on the transmission network or as a result of insufficient wholesale supply). In addition, some factors are a result of extreme events (e.g. third-party damage, extreme weather). The most common causes of unplanned outages are asset failure, vegetation and weather (Figure B.2). However these vary by distributor.

Figure B.2 Distributor causes of unplanned outages (2018-19)



Data source: AER, 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.[86] 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.[87]

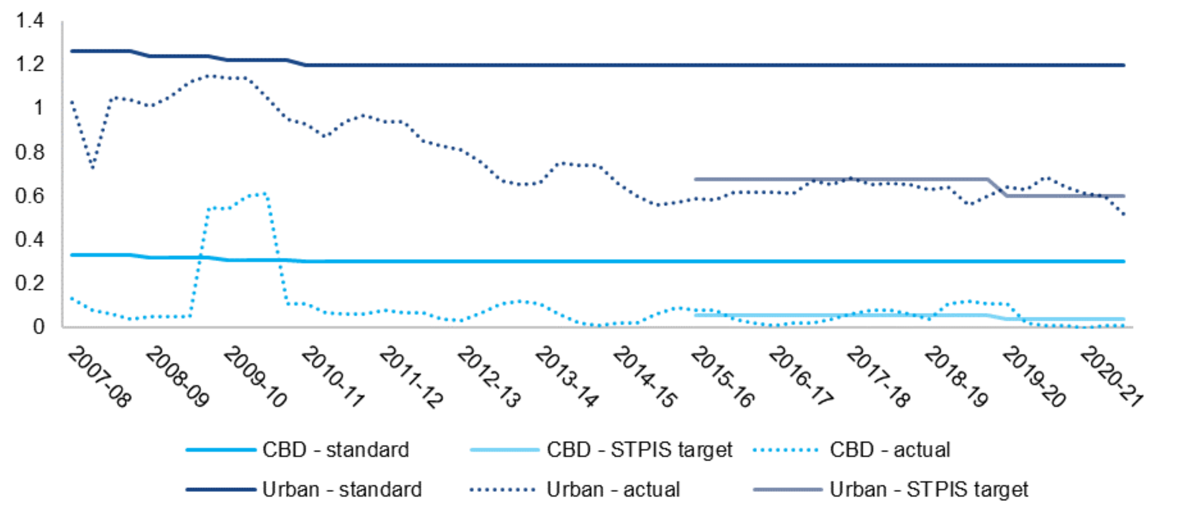
B.2.2 Distributors' overall network reliability performance is better than the standards

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

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 (i.e. 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 (i.e. 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).

ss 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 March 2021

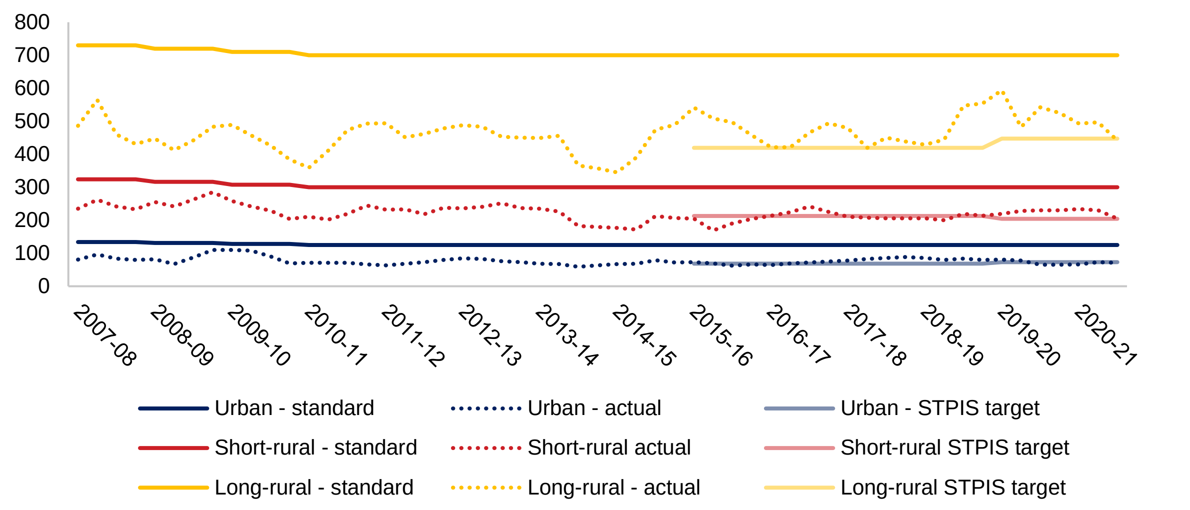


Data source: IPART analysis of information provided by Ausgrid.

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 March 2021



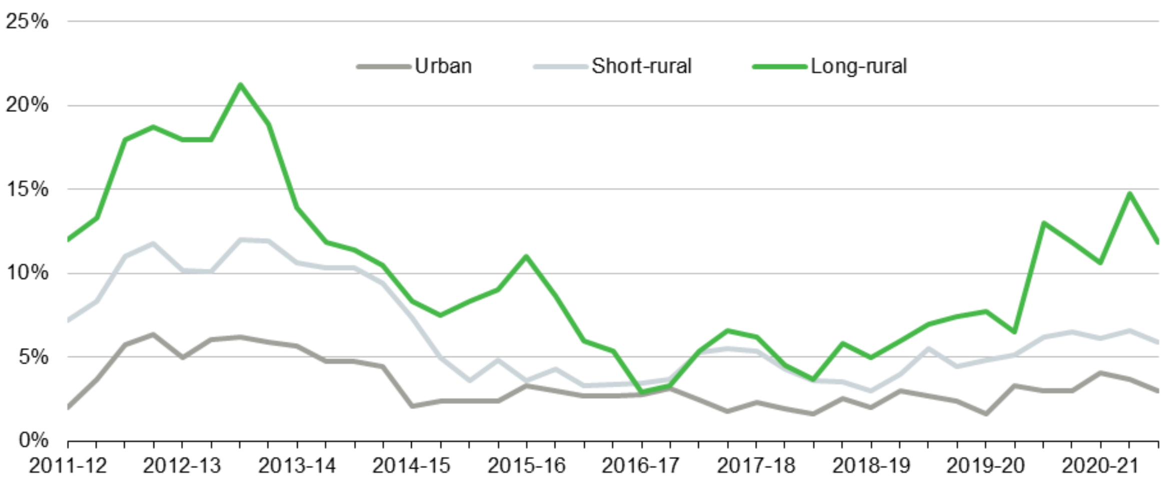
Data source: IPART analysis of information provided by Essential Energy.

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 March 2021



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 in April 2019.[88]

In their 2019-24 proposals, all three distributors proposed maintaining current levels of reliability.[89] 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.[90]

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

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.[91]

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 (i.e. the 2014-19 determination period)
- Excludes specific upstream events from the target in a similar way to the licence conditions.

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.[92]

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.[93]

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.[94]

In the most recent NSW 2019-2024 AER determinations distributors did not propose large expenditures for DER.[95] However, South Australia and Queensland are the two states with the highest penetration of embedded generation (primarily rooftop solar PV systems). Box B.3 on the following page summarises how this has impacted the AER's recent revenue determinations for the distributors in these states.

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.[96]

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 AER, *Final decision, SA Power Networks Distribution Determination 2020 to 2025*, June 2020, p 9, accessed 2 October 2020.

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

C Our approach

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 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:

- decide on the role and objectives of the licences, considering the interaction between the licences and other reliability incentives regulated by the AER
- decide on what standards are necessary to meet the licence role and objectives
- decide how to set the necessary standards
- decide on the appropriate licence monitoring and compliance framework.

The sections below discuss these steps.

C.1 What are the role and objectives of the licences?

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 AER’s 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?

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:

- 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?

We then decided how to set the necessary standards. We considered:

- 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 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 decided to exclude feeders greater than 500 km in length from our analysis as they produced anomalous results.

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. Given the complexity of modelling this network and the high level of current reliability, we decided to maintain the current standards for individual CBD feeders.

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.

We had regard to the processes underway at the national level relating to efficiently integrating DER into the energy market and the relevant NER draft changes that the AEMC has proposed recently.

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 recommendations under the assumption that this will have occurred by 1 July 2024, the date from which we have recommended that our 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.

[1] Essential Energy, Submission to Issues Paper, May 2020, p 11.
[2] AER's Post-tax Revenue Models (available from the AER's website) and IPART calculations. Figures in $2018-19, rounded to the nearest million.
[3] See Essential Energy, Submission to Draft Report, p 18.
[4] Ausgrid, Submission to Issues Paper, May 2020, p 19.
[5] Endeavour Energy, Submission to Issues Paper, April 2020, p 10.
[6] AER, Distribution Reliability Measures Guideline, 2018, p 6.
[7] Essential Energy, Submission to Draft Report, p 18.
[8] Essential Energy, Submission to Issues Paper, May 2020, p 17.
[9] Ausgrid, Submission to Issues Paper, May 2020, p 20.
[10] AER, Explanatory Statement – Amending the Service Target Performance Incentive Scheme (STPIS) and Establishing a Distribution Reliability Measures Guideline (DRMG), 2018, p 18.
[11] IEEE Std. 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices, pp 10-13.
[12] Cainey, J., Resilience and Reliability for Electricity Networks, CSIRO Publishing – The Royal Society of Victoria 131, pages 44-52, 2019.
[13] NSW Department of Planning, Industry and Environment, Fire and the environment 2019-20, Summary, p 5.
[14] Essential Energy, Submission to the Draft Report, p 16.
[15] Endeavour Energy, Submission to the Draft Report, p 2.
[16] Essential Energy, Submission to the Draft Report, p 7
[17] Ausgrid, Submission to the Draft Report, p 8; Endeavour Energy, Submission to the Draft Report, pp 3-4.
[18] Essential Energy, Submission to the Draft Report, p 7.
[19] Ausgrid, Submission to the Draft Report, pp 8-9, 16.
[20] Essential Energy, Submission to the Draft Report, p 6.
[21] Ausgrid, Submission to the Draft Report, pp 8-9, 16.
[22] Essential Energy, Submission to the Draft Report, p 8.
[23] Endeavour Energy, Submission to the Draft Report, p 2.
[24] Energy Networks Australia, Submission to the Draft Report, p 3.
[25] Letter from Ausgrid, Licence conditions for CBD network, 3 December 2020.
[26] Ibid.
[27] See IPART website, Electricity Distribution Reliability Standards 2020, accessed 5 May 2021.
[28] PIAC, Submission to the Draft Report, p 2.
[29] Schedule 3 of Ausgrid's licence dated 28 November 2016, and varied by instruments dated 4 December 2017 and 5 February 2019
[30] Essential Energy, Submission to the Draft Report, p 19.
[31] See Ausgrid, Submission to the Draft Report, p 13, Essential Energy, Submission to the Draft Report, p 9.
[32] IPART, *Review into Guaranteed Customer Service Standards and operating statistics – Draft Recommendations*, September 2003, p 27
[33] Essential Services Commission, *Electricity Distribution Code review – customer service standards,* 22 December 2020.
[34] IPART, *Review of Guaranteed Customer Service Standards and Operating Statistics,* Final Recommendations – Report to Minister, April 2004, p 7.
[35] Schedule 5 of each distributor's licence.
[36] Essential Services Commission, *Electricity Distribution Code review – customer service standards,* 22 December 2020, and AER, *Service Target Performance Incentive Scheme v 2.0,* 13 December 2018, pp 19-22.
[37] For example, Schedule 5 of Essential Energy's licence.
[38] Ausgrid submission to IPART Draft Report, January 2021, p 17 and Essential Energy submission to IPART Draft Report, January 2021, p 12.
[39] Public Interest Advocacy Centre submission to IPART Draft Report, January 2021, p 3.

[40] Ausgrid submission to IPART Draft Report, January 2021, p 3 and Essential Energy submission to IPART Draft Report, January 2021, p 1.
[41] Public Interest Advocacy Centre submission to IPART Issues Paper, 8 May 2020, p 4.
[42] Ausgrid submission to IPART Draft Report, January 2021, p 19.
[43] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 49.
[44] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 8.
[45] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 7.
[46] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 8.
[47] AG Murf Australia Pty Ltd submission to IPART Draft Report, November 2020, p 1.
[48] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 8.
[49] HoustonKemp Economists, *Distributors' incentives to efficiently incur DER export expenditure*, July 2020, p 8.
[50] Ausgrid submission to IPART Draft Report, January 2021, p 3; Endeavour Energy submission to IPART Draft Report, January 2021, p 6.
[51] Essential Energy submission to IPART Draft Report, January 2021, p 13.
[52] Endeavour Energy submission to IPART Draft Report, January 2021, p 6.
[53] Energy Networks Australia submission to IPART Draft Report, January 2021, p 1; Ausgrid submission to IPART Draft Report, January 2021, p 3; PIAC submission to IPART Draft Report, January 2021, p 3.
[54] Ausgrid submission to IPART Draft Report, January 2021, pp 19-20.
[55] Ausgrid submission to IPART Draft Report, January 2021, p 21; Essential Energy submission to IPART Draft Report, January 2021, p 13.
[56] Endeavour Energy submission to IPART Draft Report, January 2021, p 6.
[57] Ausgrid submission to IPART Draft Report, January 2021, p 20; Essential Energy submission to IPART Draft Report, January 2021, p 13.
[58] Ausgrid submission to IPART Draft Report, January 2021, p 20; Essential Energy submission to IPART Draft Report, January 2021, p 3; Endeavour Energy submission to IPART Draft Report, January 2021, p 6.
[59] See AEMO DER Register, accessed 24 May 2021.
[60] See Access, pricing and incentive arrangements for distributed energy resources, accessed 25 March 2021.
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[63] 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).
[64] Essential Energy, Submission to Draft Report, p 14.
[65] Essential Energy, Submission to Draft Report, p 14.
[66] Australian Energy Market Commission, *Review of the regulatory frameworks for stand-alone power systems – priority 1,* Final Report, 30 May 2019, p iii.
[67] See AEMC, Updating the Regulatory Framework for Distributor-Led Stand-Alone Power Systems Final Rules, May 2020.
[68] Essential Energy, Submission to Draft Report, pp 14-15.
[69] Clean Energy Council, Submission to Draft Report, p 4.
[70] 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).
[71] Clean Energy Council, Submission to Draft Report, p 1, Ausgrid, Submission to IPART Draft Report, p 22.

[72] Essential Energy, Submission to Draft Report, p 14.
[73] PIAC, Submission to Draft Report, p 2.
[74] Endeavour Energy, Submission to Draft Report, p 6.
[75] Essential Energy, Submission to Draft Report, p 14.
[76] IPART, *Annual Compliance Report - Energy network operator compliance during 2018-19,* pp 13-14
[77] 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.
[78] Endeavour Energy submission to IPART Issues Paper, May 2020, p 14.
[79] *Electricity Supply Act 1995*, Schedule 2, Clause 11.
[80] Distributors also deliver electricity to a small number of customers who are not connected via distribution feeders. These are typically large industrial customers.
[81] AER, Values of Customer Reliability - Final Decision, 2019, p 4.
[82] AER, Values of Customer Reliability - Final Decision, 2019, p 4.
[83] Endeavour Energy Distribution Annual Planning Report, 2019 DAPR, December 2019, p 6.
[84] 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
[85] AEMC, Fact sheet: what is transmission reliability? 2013, Accessed 20 February 2020.
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[88] AER, *AER decisions deliver efficient costs for NSW electricity distributors,* 30 April 2019 accessed 25 February 2020
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[94] Energy Security Board, The Health of the National Electricity Market, 209, p 18, Accessed 27 February 2020.
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[96] AER, *Values of Customer Reliability*, p 3, Accessed 21 February 2020.