2 June 2022

Essential Services Commission of South Australia
GPO Box 2605
ADELAIDE SA 5001

Attention: Rowan McKeown, Senior Policy Officer

Dear Rowan,

SA Power Networks' submission – Electricity Distribution Code Review – Issues Paper

SA Power Networks welcomes the opportunity to make a submission to the Essential Services Commission of South Australia's (the Commission) Electricity Distribution Code (the Code) Review – Issues Paper and provides the following comments the matters raised in the Issues Paper and some additional matters.

In summary, we:

- propose that the Code not only apply to SA Power Networks but to other distributors who are licensed to distribute electricity from the National Electricity Market (NEM) over public land in South Australia,
- highlight two more issues than those discussed in the Issues Paper. The two issues are:
  1. the ongoing technical and operational requirements which cease to apply to some distributed energy resources (DER) when customers move into existing premises with DER, and
  2. the potential for Virtual Power Plant (VPP) operators to cause individual customers with DER to breach their connection contract with SA Power Networks,
- advocate for the retention of Chapter 3 of the Code and for it to obligate customers to comply with the ongoing technical and operational requirements for customers who move into premises where DER are already installed,
- are concerned at the recent performance of the Adelaide CBD network and, subject to customer consultation, may include in our Regulatory Proposal for the 2025-30 Regulatory Control Period (RCP) a long-term programme to replace aging cables within the CBD,
- do not consider that the Commission needs to be involved in regulating reliability standards for regulated Standalone Power Stations (SAPS) on the basis that these are adequately dealt with under the existing regulatory framework, but that the Guaranteed Service Level (GSL) payment scheme should be extended to customers supplied from SAPS,
- consider that the Commission should be involved in regulating public lighting services until the end of the next RCP (ie until 30 June 2030) but that the current streetlight out GSL payment regime requires amendment and simplification. The current scheme is complex, costly, inefficient and penalises SA Power Networks for reasonable performance,

- propose that the Commission includes in the Code, Network Planning Criteria (essentially safety net standards), which permits certain augmentation of the distribution system to provide resilience to High Impact Low Probability (HILP) events. Customer research indicates that, in light of climate change and expected increased severe weather events, customers support increasing the resilience in the distribution system to mitigate the impact of HILP events, and
- propose that the Commission consider reviewing the customer service measures in the Code, as recent research indicates that the current customer service measures are now less relevant to customers. Quantitative customer research undertaken in late 2021 indicated that 'speed in responding to telephone calls' was ranked lowest of 19 customer service attributes surveyed.

SA Power Networks provides its detailed comments on the review of the Code in the attachment to this covering letter.

If you wish to discuss this submission or clarify any points, please contact Mr Grant Cox on 08 8404 5012.

Yours sincerely

Mark Vincent
General Manager Strategy and Transformation

Submission – ESCOSA Electricity Distribution Code review – Issues Paper

April 2022

3 June 2022

SA Power Networks

www.sapowernetworks.com.au

1. Executive Summary

The Commission has raised the following matters in its Electricity Distribution Code (The Code) Issues Paper:

- Application of the Code
- Distributed energy resources (DER)
- Review of existing provisions for the connection of embedded generators (EDC Chapter 3)
- Minimum service reliability standards
- Consumer protections for Stand-Alone Power Systems (SAPS), and
- Streetlight repair obligations.

This submission sets out SA Power Networks' views on these matters and raises two additional matters:

- Network Planning Criteria, and
- Customer service measures.

Application of the Code

SA Power Networks considers that the Code should apply to all licensed distributors who distribute electricity from the National Electricity Market (NEM) to customers over public land, as their customers should receive the same protections that the Code provides to SA Power Networks' customers.

Distributed Energy Resources

The Commission has undertaken a review of the State and national frameworks regarding DER, consulted with national and State bodies and concluded that most of the identified risks to consumers are being or will be adequately addressed in the State or national regulatory frameworks. However, SA Power Networks has identified some additional risks to consumers from DER, which were not raised in the Issues Paper.

The first is related to risks posed to consumers from the significant increase in the size of 'small' generators[1] from 30kW to 1,500 kW. This increase has occurred since the introduction of the National Energy Customer Framework (NECF)[2] and the Deemed Standard Connection Contract (DSCC) in SA in February 2012. A generator with an export capacity of more than 30kW can adversely impact parts of the distribution network and consumers connected to those parts of the distribution network. SA Power Networks has developed connection contracts with generators where the capacity to export exceeds 30kW. Those contracts ensure that embedded generators do not adversely affect the network and other consumers.

In addition, even customers less than 30kW can, in aggregate, have significant impacts on other customers within parts of the network. When these customers apply to connect their generating

1 Under the EDC and the National Energy Retail Rules a small generator is an inverter connected generator that complies with AS4777. An embedded generator complying with AS 4777 must be connected at low voltage. SA Power Networks will only permit a generator with a capacity to export no more than 1,500kW to be connected at low voltage.

2 The NECF comprised creation of the National Energy Retail Law, the National Energy Retail Rules and amendments to the National Electricity Rules.

system, they agree to comply with a standard contract that ensures they do not impact on other customers.

However, where a consumer moves into a premises with a small generator our embedded generation contracts cease to exist, and under the NECF only the DSCC applies to those customers. The NECF prevents us from including obligations on 'small' generators beyond what is included in energy laws. SA Power Networks is not permitted to include technical and operational requirements on consumers with small generators to ensure that other consumers or the distribution network are not adversely affected. SA Power Networks considers that these risks could be addressed by the retention and amendment to Chapter 3 of the Code.

The second issue is the control and operation of consumers' small generators by Virtual Power Plant (VPP) operators. The AEMO VPP trial has demonstrated that VPPs can be extremely responsive to market price signals and can quickly switch operation from charge to discharge, enabling them to provide a range of valuable market services such as Frequency Controlled Ancillary Services (FCAS). Therefore, VPPs have the potential to play an important role in the security, stability and efficient operation of the Market.

AEMO's VPP trial indicates that VPPs can effectively respond to power system events and price signals. This includes responding to frequency excursions beyond the normal operating range (49.85-50.15 Hz) and pre-charging (or discharging) to cater for future high (or low) price events, respectively. This behaviour can generate significant swings in both electricity consumption and export. These swings can be managed at a 'whole of system' level by AEMO like other generators, but unlike these larger generators, the VPP may also be subject to a variety of local constraints within the distribution network. Depending on where each electricity generating plant is located, these could impact on the security, reliability, and quality of supply for other electricity customers.

We consider that it is important that VPPs only operate consumers' small generators within the constraints of the distribution network, so as to not impact on the security, reliability and quality of supply for other customers. SA Power Networks has no contractual relationship with VPPs. If a VPP operates a consumer's small generator so that it adversely impacts other consumers, we cannot take action against the VPP but only the consumer, as we have a connection agreement with that consumer. It would be unfair to penalise a consumer for the actions of a VPP. We consider that this risk should be addressed by the SA Government's current review of the electricity licensing framework. We have submitted to the Government's current review that VPPs should have an operating agreement with SA Power Networks to ensure that they do not result in the small generators controlled by them breaching their connection agreement with us.

The Code chapter 3

SA Power Networks advocates for the retention of Chapter 3 of the Code, as it mandates technical requirements that SA Power Networks relies on when connecting embedded generators. Chapter 3 could also be used to address the first issue raised by SA Power Networks, that is: to ensure appropriate ongoing obligations for customers who move in into premises with existing small generation and larger generators connected under Chapter 5A of the Rules. SA Power Networks has reviewed Chapter 3 and proposed amendments to it, which are detailed in this submission (see Section 3.3.c)

Minimum service reliability standards

The Commission has raised concerns with the annual reliability performance of the Adelaide CBD where the performance has been poorer than some of the targets. The poor performance has been due to several factors including the condition of the older cables in the CBD. To maintain the reliability of the CBD in the longer term, SA Power Networks needs to commence a long-term program to replace the older cables in the CBD.

The reliability of the CBD network is critically important, to CBD consumers and the wider community. We consider that the current CBD reliability targets are appropriate and should be retained for the 2025-30 Regulatory Control Period (RCP). We note, however, that the recent performance of the Adelaide CBD is worse than other National Electricity Market CBDs.

We have engaged a cable expert to assist us determine the condition of our older CBD cables and develop a risk-based programme targeting the replacement of those cables. We will be consulting with consumers on the expected expenditure that will be required over the next and future RCPs to address the declining condition of these older cables.

Due to recent changes to energy laws distributors are now permitted to take consumers off-grid and supply them from a regulated SAPS. It is only possible to take consumers off-grid where it is efficient to do so (eg the cost to supply customers from a SAPS is lower than maintaining their grid connection). The laws for 'Distributor-led SAPS' provide the same customer protections as if they were still connected to the Grid. Distributors must consult with affected customers and stakeholders prior to them being taken off-Grid and the reliability and quality of supply to those consumers supplied from SAPS must be the same or better than if they were still connected to the Grid.

SA Power Networks considers that the Commission does not need to establish reliability standards for SAPS customers, as the national framework provides sufficient protections. The Distributor-led SAPS framework ensures customers are treated as if they are still connected to the Grid and the current on-Grid guaranteed service level (GSL) standards (eg reliability GSL payments) will apply to consumers supplied from SAPS.

Streetlight Repairs.

The Commission currently has two roles in street lighting which are:

- Monitoring SA Power Networks' streetlight repair performance; and
- Setting the Street Light Out (SLO) Guaranteed Service Level (GSL) payment regime.

SA Power Networks provides public lighting services for 67 public lighting customers throughout South Australia, including local councils and the South Australian Department of Infrastructure and Transport (DIT).

Public lighting improves the safety and amenity of our local communities through the supply, installation and maintenance of public lights across South Australia. There are approximately 230,000 luminaires / public lighting installations across our network. The delivery of public lighting services involves the ongoing maintenance, inspection, and operation of these public lighting installations.

A Public Lighting Working Group (including Councils, DIT, Local Government (Association LGA) and SA Power Networks) was formed in 2018. SA Power Networks has actively consulted with the PLWG members to better understand their preferences for setting service standards for public lighting into the future.

The PLWG have expressed a preference for the Commission to continue to set service standards and monitor SA Power Networks ongoing performance, and therefore propose no change to the framework for the 2025-30 regulatory period. Noting the continued development in public lighting technology, particularly the introduction of smart lighting, we recommend that the Commission's involvement be reviewed again prior to the 2030-35 regulatory period.

However, the PLWG have acknowledged there are issues with the current GSL scheme and supported a detailed review including the structure and application.

The GSL regime that operates in other jurisdictions provides a single GSL payment to the first-person to report the SLO if not repaired in the specified time, where the reporter occupies a residence or business adjacent to the streetlight.

The NSW public lighting framework also splits street light faults into 'general' and 'complex' and provides 10 business days to repair general faults and 30 business days for complex faults. SA Power Networks recommends that its streetlight faults should be split into these same two categories as it is not practical to repair a streetlight cable fault in five business days. If the NSW regime was operating in SA we would have 30 business days to repair a cable fault. If we made repairs by, say, the 28th business day, no GSL payment would be required. In comparison, under the existing South Australian GSL regime we would make a $125 GSL payment (ie 5 times the single SLO payment) to the first person who reported the SLO. SA Power Networks should not be penalised (ie making a GSL payment) where the repair of the fault is efficient and practical.

The current South Australian streetlight SLO GSL payment regime is complex, costly and provides an incentive for 'serial' reporters to maximise GSL payments by:

- 'dumping' large numbers of SLOs (we have experienced 40 or more) in a single night/report; and
- reporting working streetlights as an SLO[3].

This behaviour overwhelms our ability to respond efficiently and repair genuine SLOs reported within the specified guaranteed time. During 2020-21 more than 15% of SLOs reported by serial SLO reporters were found to be working when we attended to make repairs. This compares to less than 3% of SLOs reports provided by other SLO reporters (who report 2 or less in the year). This highlights a perverse incentive within the current scheme for serial reporters to report working streetlights as an SLO, resulting in inefficient costs to SA Power Networks and ultimately all consumers.

SA Power Networks compared the streetlight fault repair performance of other mainland distributors who have a simple SLO GSL regime and found that our repair performance was similar. SA Power Networks therefore advocates for a simplified SLO GSL regime that limits a SLO payment to a single payment for one light and provides different repair times for general and complex faults.

Network Planning Criteria.

SA Power Networks has long-standing internal planning criteria (Planning Criteria) for augmenting the distribution network. The Planning Criteria ensures we comply with reliability standards and mitigates the risk to consumers from High Impact Low Probability (HILP) Events.

Most distributors in the NEM use a probabilistic planning approach to determine when to augment their network. The distributor's network will only be augmented under a probabilistic approach when the expected annual cost to consumers[4], exceeds the annualised costs of the augmentation. A probabilistic planning approach does not justify augmentation expenditure to mitigate the risk to

[3] In calendar year 2018 and 2019 serial reporters reported 1,000 SLOs of which 28% were found to be working when attended. The serial reporter was paid $9,000 in GSL payments but we incurred nearly $25,000 to attend working streetlights. These crews could have attended and repaired streetlight which were not working. In calendar years 2018 and 2019 14% of SLO reports were for working streetlights, which cost in in excess of $0.6m to attend.

[4] As determined using AER values for customer reliability, the likely duration of the event, and the probability of the event occurring.

consumers from a HILP event, as while the cost of the event is very high, the probability is extremely low.

In the AER's 2020-25 distribution determination for SA Power Networks, our Planning Criteria was subject to critique by the AER and its engineering consultant, who questioned the standing of the Planning Criteria on the basis that the criteria were developed by SA Power Networks rather than by a jurisdictional regulatory body, as occurs in some other jurisdictions. We consider that it is likely that in its current form, the AER may be reluctant to consider the Planning Criteria as relevant to guiding appropriate investments to safeguard service to South Australians in the 2025-30 period and beyond. Given this concern, we engaged a consultant (Cutler Merz), to advise whether we should adopt a probabilistic planning approach.

Cutler Merz investigated several network planning options including our Planning Criteria, a more probabilistic approach, Queensland's (QLD) distributors' Safety Net and New South Wales (NSW) previous Security Standard. Cutler Merz determined that until 2030, our Planning Criteria would deliver similar levels of augmentation expenditure as compared with a more probabilistic approach. Cutler Merz recommended that we adopt a probabilistic approach to network planning but recommend the Commission include planning criteria in the Code as a minimum safety net standard to mitigate against HILP events and to maintain long term network resilience.

Cutler Merz determined that, if South Australia adopted the QLD safety net standard or the NSW Security Standard, either would drive considerable extra augmentation expenditure. Cutler Merz is therefore not advocating that we adopt the Qld Safety Net in the Code but suggests codifying SA Power Networks' existing Planning Criteria or a simplified version. This implementation would maintain risk to customers at current levels and would not increase future augmentation expenditure beyond historic levels.

Feedback from customer engagement undertaken recently by SA Power Networks indicates a desire from customers to maintain network resilience, and if necessary, fund additional 'resilience' network expenditure to mitigate impacts from HILPs.

Customer Service Measures.

SA Power Networks retains its concern, expressed during the process for setting the customer service measures for 2020-25 RCP, that the current customer service measures may have become less relevant for customers.

In particular, we consider that the measure relating to answering a telephone call within 30 seconds, is no longer appropriate. This was rated as least important to customers in recent quantitative customer research that asked customers to rank a range of different service attributes in order of importance. There has also been a significant reduction in the number of telephone calls SA Power Networks received from customers since 2005-06 when the measure was initially introduced.

However, the number of written enquiries (which now include social media enquiries) from customers has significant annual variation but appears to still be relevant for customers, with social media increasingly becoming a channel of choice for customers to contact SA Power Networks.

Since 1 April 2018 we have been measuring these additional customer satisfaction measures, and have been reporting these to the Commission since 1 July 2020 which focus on how effectively we communicate with customers in the following areas:

- Planned interruptions
- Unplanned interruptions

- General enquiries
- New connections, and
- Customer complaints.

These measures are based on surveys of customers who have experienced those interactions in the past month. There are several distributors which are also using these monthly customer satisfaction measures, so we can compare our performance with other distributors.

SA Power Networks has recently been surveying customers on our ability to resolve a customer issue during their first contact. This could prove a useful measure to drive better outcomes for consumers.

SA Power Networks is about to commence engagement with customers on preferred customer service measures and whether answering telephone calls in 30 seconds remains a priority, or whether a measure of customer satisfaction or first enquiry resolution is more valued by customers. We also intend to explore customers' communication channel preferences and trends and investigate whether there is merit in focussing on emerging channels such as social media and other digital platforms. We will keep the Commission informed of the outcomes of this engagement which we expect to be complete by early 2023.

2. Definitions

Definitions of terms used in this report:

Term	Definition
2010-15 RCP	2010-15 Regulatory Control Period or 1 July 2010 to 30 June 2015.
2015-20 RCP	2015-20 Regulatory Control Period or 1 July 2015 to 30 June 2020.
2020-25 RCP	2020-25 Regulatory Control Period or 1 July 2020 to 30 June 2025
2.5β method	The IEEE Std 1366™-2012 2.5 Beta statistical method used to calculate T_{MED}.
AER	Australian Energy Regulator
API	Application Programme Interface (a standard internet-based interface)
BoM	Bureau of Meteorology
CBD	Central Business District feeder category
DSCC	The ongoing Deemed Standard Connection Contract as specified in the Retail Rules
DRSP	Demand Response Service Providers
The Code	South Australian Electricity Distribution Code
The Commission	The Essential Services Commission of South Australia
IEEE	US Institute of Electrical and Electronic Engineers Inc
MED	Major Event Day – any day where the daily USAIDI accrued on that day, exceeds a predetermined USAIDI threshold. The threshold is determined in accordance with the IEEE Std 1366™-2012 2.5 Beta statistical method.
NECF	National Energy Customer Framework
PV	Photovoltaic
USAIDIn	Normalised USAIDI (USAIDI excluding interruptions that start on MEDs)
USAIFIn	Normalised USAIFI (USAIFI excluding interruptions that start on MEDs)
RCP	Regulatory Control Period means the period of a regulatory distribution determination by the AER.
Retail Rules	The National Energy Retail Rules
Rules	The National Electricity Rules.
STPIS	The AER's Service Target Performance Incentive Scheme with provides incentive for distributors to maintain or improve reliability performance.
SWE	Significant Weather Event as reported by the BOM in their monthly weather review.
T_{MED}	The daily USAIDI threshold used to determine if a day will be classified as a MED.
UCAIDI	Unplanned Customer Average Interruption Duration Index (ie average time taken to restore supply to customers as a result of an unplanned interruption)
USAIDI	Unplanned System Average Interruption Duration Index – total number of minutes, on average, that customers are without electricity as a result of unplanned interruptions[5] in a year.

[5] Excludes interruptions where the duration is less than three minutes.

USAIFI	Unplanned System Average Interruption Frequency Index – average number of times customers' supply is interrupted per year from unplanned interruptions.

3. APPLICATION OF THE CODE

3.1 Electricity Distributors

The Commission is seeking stakeholder responses to the following question.

***Question for stakeholders**:*

The Commission is proposing to amend the Code so it applies only to SA Power Networks. Do you support this approach? If not, why not?

SA Power Networks considers that the Code should apply to any licensed distributor who supplies electricity from the NEM to their customers over public land. This would ensure that the customer protections provided to SA Power Networks' customers (eg reconnecting electricity supply after disconnection) would also protect the customers of that other licensed distributor.

3.2 Embedded Generators

The Code is an industry code that applies to the conduct of the electricity supply industry and regulated entities. Specifically, regulated entities would include both licensed generators and generators exempt from licensing that are required to comply with the Code.[6] It is therefore appropriate, and in our view, essential, that the Code applies to embedded generators whether licensed (as required by the Electricity Act) or exempt[7] from being licensed by the Electricity (General) Regulations (Technical Regulations) s15(2). Consequently, all embedded generators are required to comply with Chapter 3 of the Code. Given the volume of embedded generation on our network and the active measures which SA Power Networks has implemented, and will continue to develop, SA Power Networks relies on the requirement for embedded generators to comply with the Code, especially the requirements that apply to embedded generation.

SA Power Networks requests that Clause 3.1.1(a) be removed from the Code as we believe it is inconsistent with Clause 1.1.2 that we believe more accurately reflects when the Code should and should not apply (ie the Code should apply where it does not duplicate or is not inconsistent with the National Electricity Rules (The Rules)).

3.3 Distributed Energy Resources (DER)

3.3.a Interaction of DER with the distribution network – risks to consumers

DER are energy units or systems that are located on the consumer side of the meter, commonly located on houses or businesses, including rooftop PV panels (ie small embedded generators), batteries (which can be a load or a generator), electric vehicles, energy management systems and

[6] The Electricity (General) Regulations s15(5) requires that a person exempt or granted exemption from being licensed as a generator must comply with the National Electricity Rules or a code made by the Commission (eg the Code).

[7] A person who carries on the generation of electricity is exempt from the requirement to hold a licence under the Act authorising the operations if— (a) the generating plant has a rated nameplate output of 100 kVA or less; or (b) the person does not supply electricity for reward to or by means of a transmission or distribution network.

larger stand-alone generators. DER may be operated by individual customers, or coordinated as part of a Virtual Power Plant (VPP).

The Commission is seeking stakeholder responses to the following question.

> ***Question for stakeholders***:
>
> *From the consumer's perspective, are there risks posed by the interaction of DER with the distribution network that the Commission has not considered? If so, are these risks best addressed by the Commission?*

The Commission has concluded that most of the risks to customers from DER are being, or will be, addressed elsewhere (ie not by the Commission) in the State or national regulatory frameworks. SA Power Networks has identified some additional risks, detailed below, which are not raised in the Issues Paper.

When the Embedded Generation Chapter of the Code was last reviewed it specified that a small embedded generator was an embedded generator which owns, operates or controls an embedded generating unit[8] that complies with the requirements of AS 4777 (ie inverter connected generator). This is a similar definition to a small generator in the National Energy Customer Framework's (NECF) Deemed Standard Connection Contract (DSCC). The capacity of a generating unit complying with AS 4777, when it was incorporated in the Code and in the DSCC was a maximum of 30kW (or a maximum of 10kW per phase). A generator of this capacity is automatically exempt[9] from being licensed by the Electricity Act. Generators of this capacity or less are normally installed by residential and small business customers.

SA Power Networks would consider a generator with a capacity of more than 30kW to not be a small generator as, individually, they may have a negative effect of the quality of supply to other customers. The current version of AS 4777 has been amended twice, with each amendment increasing the capacity of a generating unit. The current version of AS 4777 does not specify a specific capacity limit other than it must be connected at low voltage[10]. SA Power Networks limits the capacity of a generator connected to low voltage to 1.5MVA (or 1,500 kVA).

SA Power Networks is responsible for the quality of supply and the reliability service level provided to customers. The Commission has highlighted that DER can affect the quality of supply of customers, especially where congestion in the network occurs. SA Power Networks manages the risk posed by DER to the reliability, security of supply and the quality of supply by establishing connection contracts with customers who install DER or upgrade their existing DER capacity (eg PV).

The three DER contracts SA Power Networks has developed to manage the DER risk are summarised in the table below.

Table 1 SA Power Networks DER connection contracts

DER export capacity	Comments
≤ 10 kW per phase (maximum of 30kW)	DER connected under the Rules Chapter 5A, using a basic connection contract[11] approved by the Australian Energy Regulator (AER). The contract includes SA Power Networks technical requirements for connection and export of the DER. Also SA Power Networks' technical

8 Embedded generator means and generating unit which is connected to a distribution network and does not have direct access to a transmission network.

9 The Technical Regulation s15(2).

10 SA Power Networks limits the capacity of generator of a kind contemplated by AS 4777 to 1,500 kW.

11 Model standing offer for basic connection services as approved by the AER.

DER export capacity	Comments
	standard TS 129 "Small EG Connections Technical Requirements – Capacity not exceeding 30kVA" also applies.
>30 to ≤ 200 kW	DER connected under the Rules Chapter 5A, using a negotiated connection contract developed by SA Power Networks. The contract includes SA Power Networks technical requirements for connection and export of the DER. TS 132 Low Voltage Embedded Generation Connection Technical Requirements – Capacity exceeding 30kVA applies.
> 200kW	DER connected under the Rules Chapter 5A, using a negotiated connection contract developed by SA Power Networks. The contract includes SA Power Networks technical requirements for connection and export of the DER and includes the requirement for remote control equipment for that enables the DER to not export to the distribution system, when dictated by us. TS 132 Low Voltage Embedded Generation Connection Technical Requirements – Capacity exceeding 30kVA or TS133 High Voltage Embedded Generation Connection Technical Requirements applies. This connection contract also applies to Registered Participants or customers who elected to connect their embedded generator under Chapter 5 of the Rules.

Other than Registered Participants[12], where a customer moves into a premises with existing DER, SA Power Networks' DER connection contracts (detailed in Table 1 above) cease to apply. The current Code imposes some technical requirements on large generators[13]. For any move-in customer (residential or small business) with existing DER are only required to comply with the DSCC[14]. The DSCC and the Retail Rules[15] only permit reference to standards called up by energy legislation and no reference to a distributor's standards. Distributor standards currently only apply to the customer who installs or upgrades their DER. We request that the Code include reference to our technical standards or include standards and operational requirements on DER that is connected under Chapter 5A of the Rules. This would allow SA Power Networks to require ongoing compliance with its technical standards (eg TS129 Small EG Connections Technical Requirements - Capacity not exceeding 30kVA) and enable SA Power Networks to undertake measures such as Enhanced Voltage Management (EVM)[16] and dynamic export limits where necessary for network stability and continue to manage the quality of supply and other effects of DER on our distribution system. We consider this is a material risk from DER which is not adequately addressed elsewhere in the State or national regulatory frameworks.

12 A Registered Participant has an ongoing obligation to comply with the technical requirements of the Rules and operate the plant in accordance with SA Power Networks connection agreement for that premises.

13 A large generator is defined in the EDC as not a small embedded generator. Therefore, a large embedded generator is a synchronous generator or an inverter controlled generator which is connected at high voltage.

14 The DSCC as detailed in Schedule 2 of the Retail Rules. See clause 6.6(a) and Retail Rule 147A(1).

15 Retail Rules rule 147A

16 EVM id used to safely raise the voltage of the distribution network that will result in PV systems being switched of my its inverter. This is only performed when there is a threat to the security of the electricity supply system.

As highlighted previously, consumers who are exempt from being licensed or are licensed to export electricity into the distribution system, must comply with the Code. SA Power Networks strongly advocates for the continuation of the Code Chapter 3 (with our proposed amendments – see Section 3.3.c), to fill this gap in the regulatory framework.

3.3.b Risks to consumers with DER from Virtual Power Plants

According to the Australian Energy Market Operator (AEMO), a VPP broadly refers to an aggregation of resources (such as decentralised generation, storage and controllable loads) coordinated to deliver services for power system operations and electricity markets.

The AEMO VPP trial has demonstrated that VPPs can be extremely responsive to market price signals and can quickly switch operation from charge to discharge, enabling them to provide a range of valuable market services such as Frequency Controlled Ancillary Services (FCAS). Therefore, VPPs have the potential to play an important role in the security, stability and efficient operation of the Market.

A VPP is different from other Distributed Energy Resources (DER) resources (eg generators) as it typically comprises many small DER located at different locations within the State and connected to our distribution network. These individual DERs can either be owned by the VPP and leased to the customer or owned by the customer who has a contract with the VPP to operate the DER on the customer's behalf.

There are also other types of 'aggregators' emerging that could manage large fleets of DER such as smart hot water, electric vehicle chargers and other customer loads under the Wholesale Demand Response mechanism. While these may not be generation resources, the effects of their operation can have similar impacts on the energy system as VPPs, and many can respond to the same suite of market services.

The AEMO's power system security responsibilities in the National Electricity Rules (NER) rule 4.3.1 cover transmission and distribution systems. However, AEMO's view is that it can assess power system security impacts in the transmission system, but that Distribution Network Service Providers (DNSPs) are best placed to do so for distribution systems.

AEMO's VPP trial indicates that VPPs can effectively respond to power system events and price signals. This includes responding to frequency excursions beyond the normal operating range (49.85-50.15 Hz) and pre-charging (or discharging) to cater for future high (or low) price events, respectively. This behaviour can generate significant swings in both electricity consumption and export. These swings can be managed at a 'whole of system' level by AEMO like other generators, but unlike these larger generators, the VPP may also be subject to a variety of other constraints within the distribution network, depending on where each electricity generating plant is located which could impact on the security, reliability, and quality of supply for other electricity customers. As DER proliferation continues and becomes a more central part of the energy system, and as VPPs grow in their aggregated size, it will be essential that DER becomes "smarter" and more aware of the constraints of the local distribution system. It must be noted that DER, when controlled by a VPP, effectively operate together, and as such can have a greater impact on the distribution system, than when operating independently. Also, this will apply to Demand Response Service Provider (DRSP), who are likely to aggregate demand from many individuals to provide services to the electricity system.

We have proposed that in the future all DER must have 'smart' capabilities in accordance with our 'LV Management Strategy'. This strategy was supported by the AER in their 2020-25 Pricing Determination on the back of significant customer and industry support. This is being introduced as part of our new "Flexible Exports" connection offering, which offers customers with DER a variable export limit, subject to network constraints, issued via a standard internet-based interface (API).

Currently in field trials, this is likely to be provided as a standard service offering after mid-2022, with further technology development currently being undertaken by SAPN and industry. At this stage we expect our flexible exports DER connection offering to provide a minimum export of 1.5kW to a maximum of 10kW, reflecting the capacity of the distribution network depending on distribution system configuration, at any particular time of day and time of the year.

We have been operating a “flexible exports” API interface with the South Australian Tesla VPP as part of a trial and intend to offer this to other VPP operators as part of a broader trial later this year.

Under the National Electricity Rules (NER) a generator must negotiate a connection agreement with the network service provider for the terms and conditions associated with the connection and access to their network. Currently, SA Power Networks negotiates an individual connection agreement with any customer with a generator or a generator who has an export capacity exceeding 30kVA. These connection agreements ensure that the operation of the customer’s generation source does not adversely impact the distribution network and other customers.

For any generators not exceeding 30kVA, SA Power Networks is not permitted to negotiate a connection contract with the customer for the operation of their DER but must rely on our deemed connection contract or on the terms and conditions of our Model Standing Offer (MSO) where the customer installed the DER.

There is currently no requirement for a VPP/aggregator to negotiate a connection agreement with the network service provider for the aggregated DER they control, even though this capacity could be 10’s or even 100’s MW. As VPPs/aggregators are typically aggregating small DER, SA Power Networks has to rely on the basic provisions within the MSO or deemed connection contract which places obligations on the customer and rely on the VPP/aggregators to operate the customer’s DER in accordance with the customer’s agreement with SA Power Networks. Where a VPP/aggregator operates an individual customer’s DER in breach of our contract with that individual, we have no option, under the current regulatory framework, than to act against the customer. This would be unfair as the VPP/aggregator is causing the breach of the connection contract not the customer.

We believe that there should be a requirement for a VPP/aggregator operator to negotiate an operating agreement with SA Power Networks to ensure that the simultaneous operation of the many individual generation plants does not adversely impact the distribution system and other customers.

3.3.c Review of existing provisions for the connection of embedded generators

The Commission is seeking stakeholder responses to the following question.

***Question for stakeholders**:*
Are there any areas where the Commission needs to maintain technical requirements for the connection of embedded generators? Why or why not?

SA Power Networks submits there is a continuing role for provisions in the Code which regulate embedded generators.

This is primarily because there are a number of regulatory gaps in the Rules and National Energy Retail Law (NERL).

Where a generator participates in the National Electricity Market (that is Chapter 5 of the Rules applies) SA Power Networks acknowledges there is no regulatory gap. Chapters 3, 4 and 5 of the Rules set out a comprehensive regime for regulation of these generators and a generator cannot participant in the NEM unless they have a connection agreement and comply with these chapters.

SA Power Networks supports the Code making clear that it does not apply to generators who are registered participants in the National Electricity Market.

The NER and the NERL also comprehensively regulate the process of a generator (not registered in the NEM) establishing their initial connection to the network. Specifically, Chapter 5A regulates the connection process in detail and connection may only occur either through a contract approved by the AER or through a contract negotiated in accordance with the provisions of Chapter 5A.

The gap in the regime is the ongoing regulation of existing generators.

In respect of small generators, they are regulated to some degree by the contract in Schedule 2 (ie DSCC) of the National Energy Retail Rules. However, that contract does not regulate the technical standards small generators must meet. Instead, it contemplates those standards should be specified elsewhere. In South Australia there is currently no place such standards are specified. SA Power Networks submits that "place" should be the Code.

In respect of large generators[17] (other than registered NEM participants) the regulatory gap is that there is a lack of regulation of existing generators. That is, Chapter 5A provides a process for connection of a new or upgrading a generator but there is nothing in the regulatory regime which requires a generator to always ensure it is party to a connection agreement with SA Power Networks. For example, suppose a 1 MW generator is connected at a site in 2018 and a connection agreement negotiated under Chapter 5A. At this point there is no issue. Then suppose the site of the generator is sold. There is no connection agreement with the new owner and so nothing regulating how that generator exports to the grid. It is unclear what rights SA Power Networks has to control the behaviour of this generator.

This issue is explored in more detail below.

3.3.c.1 Application and content of the Code

Clause 1.1.2 of the Code provides the Code only applies to a person where it is not inconsistent with a substantially equivalent provision in Part 5 (we note this should be Chapter 5) of the Rules or the NERL for there is no substantially equivalent provision in Part 5 of the NER or the NERL.

Clause 3.1.1(a) then provides Chapter 3 only applies to regulate an embedded generator's access to a distribution network in South Australia where the NER does not apply.

SA Power Networks considers these provisions are unclear, particularly having regard to Chapter 5A. The initial process of connecting all new generation to the distribution network is governed by Chapter 5A of the NER (unless Chapter 5 of the NER applies). Having regard to this, it is unclear in what circumstances Chapter 3 of the Code could apply to a generator connection.

Clauses 3.2, 3.3. 3.4 and 3.5 all regulate the connection of generators. However, SA Power Networks submits that given clause 3.1.1(a) these provisions will never have any application because all such generation connections are governed by Chapter 5A of the NER.

Given the above issues, SA Power Networks submits that:

(a) clause 3.1.1(a) should be deleted;

(b) the reference in clause 3.3.1(b)(iii) to any large generator that is not required to be registered under the National Electricity Rules be changed to *"any large generator that is not registered*

[17] SA Power Networks defines an embedded generator with an export capacity of more than 5kW single phase and more than 30kW three phase (including AS 4777 compliant generators).

under Chapter 2 of the National Electricity Rules as a generator". This change will make clearer the category of generators to which the Code does not apply – those registered in the NEM; and

(c) clauses 3.2 to 3.5 are deleted as they serve no ongoing purpose as new connections are comprehensively regulated by Chapter 5A of the Rule.

Clauses 3.6 to 3.8 regulate connection charges, extension charges and augmentation charges. SA Power Networks submits these clauses are now redundant as connection costs are exclusively regulated by Chapter 5A, the AER's connection charge guidelines and the AER's distribution determinations. Indeed clauses 3.6 to 3.8 recognise this as they essentially just say that pricing should be in accordance with the distribution determination. SA Power Networks submits it is preferable that these clauses are removed to avoid regulatory duplication.

3.3.C.2 Large Generators – the Regulatory Gap

As noted in section 1 above, the Rules and the NERL do have a major regulatory gap in respect of large generators who are not registered in the NEM.

The gap is best described by way of example.

If someone wishes to establish, say, a new 1MW generator then there is no gap. They will apply to SA Power Networks under Chapter 5A of the NER and follow the process for a negotiated connection including that both the generator and SA Power Networks negotiate in good faith (clause 5A.C.3). As well as negotiating a connection service they have the option to negotiate a supply service (clause 5A.C.1(b)).

However, suppose post connection the site of that generator is sold to another person. That generator is still connected to the network but there is now no connection agreement in place. SA Power Networks has no contractual right to control the generator, temporarily interrupt it, ensure it has the requisite protection systems or require it to comply with any requisite export limits. The integrity of the electricity distribution network is now under threat because there is a connected generator which cannot be controlled.

This issue does not arise with electricity customers. This is because when a house or site is sold the new owner automatically (by virtue of the NERL) moves onto the Retail Rules DSCC (or, if applicable, the SA Power Networks AER approved Deemed Large Customer Connection Contract).

There is no equivalent process with generators.

To address this, SA Power Networks submits that the Code should make clear that a large generator may only connect and export to the electricity distribution network if that party has a connection agreement in place with SA Power Networks. This will address the regulatory gap and ensure there is a contractual framework for all connections (both new and ongoing) enabling the ongoing management of safety and technical issues.

SA Power Networks suggests a clause along the following lines be included:

"(a) A large generator may not connect to the distribution network or export electricity into the distribution network unless it is party to an agreement with the distributor governing the terms on which that connection of the large generator is to be established and maintained and on which that export of electricity from that large generator may occur.

(b) If requested by a large generator to negotiate an agreement referred to in paragraph (a), the distributor must do so in accordance with Part C of Chapter 5A of the National Electricity Rules (whether or not Part C would otherwise apply to that request).

(c) If the owner or operator of a large generator wishes to transfer ownership of the site on which that large generator is located, the distributor must not unreasonably withhold consent to the novation of any existing connection agreement governing the connection of that large generator (but in determining whether to give consent may have regard to the reputation, financial substance and technical capability of the person to whom it is proposed the connection agreement be novated").

Paragraphs (b) and (c) are designed to provide protection to the large generator.

Paragraph (b) obliges SA Power Networks to negotiate as if Chapter 5A of the NER applied (in particular negotiate in good faith) even though the Chapter may not apply because the Chapter actually only applies to negotiation arrangements for new and upgraded connections not existing connections.

Paragraph (c) requires SA Power Networks not to unreasonably withhold consent to novation of an existing contract (thus avoiding the need for the generator to negotiate a new contract). This gives the owner selling a site the option to novate a connection agreement rather than the new owner being required to negotiate a new agreement.

We also consider it would be of benefit for a large generator to notify SA Power Networks (and potentially the Commission) of any changes in ownership of the generator so that SA Power Networks and the Commission may monitor whether new owners have the requisite technical skills and are party to an appropriate connection agreement. Given this, SA Power Networks submits the Code should include a provision to the following effect:

"If the owner of a large generator, or the site upon which a large generator is located, intends to transfer ownership of the large generator or the site it must give prior notice to the distributor [and to the Commission]."

3.3.c.3 *Small Generators – the Regulatory Gap*

Chapter 5A provides a comprehensive mechanism for small generators to connect to the distribution network. There is no need for any additional regulation of this process in the Code.

Schedule 2 of the Retail Rules sets out a contract which applies to customers who have small generators and this contract will follow ownership of the generation site. Ie if a customer sells their premises then the Schedule 2 contract will apply to the new owner.

However, Schedule 2 is in very general terms. In contrast the connection offer approved by the AER for small generators contains quite detailed provisions governing technical compliance (clause 5.5 and Attachment 3) and clause 4.2 sets out detailed provisions governing fixed and flexible exports.

The regulatory gap is that these connection offer provisions will apply to the original owner of the premises that installs the small generator. However, when the property is sold those provisions will not apply because the connection offer contract does not get transferred. There is no mechanism in the regulatory environment for this. The new owner will only be on the very general DSCC and the technical and safety provisions fall away.

The DSCC does contemplate that the jurisdictional regulatory environment will prescribe standards with which a small generator must comply. Clause 6.6(a) of that contract provides:

"If you have a small generator connected to our distribution system at the premises, you must comply with the applicable standards in operating and maintaining the generator when you use supply services under this contract. We publish information about these standards and other matters relating to small generator connections as required by the Rules. The information is available on our website or you may contact us to request a copy."

However currently in South Australia there is no regulatory document setting out the "applicable standards".

SA Power Networks submits the appropriate regulatory document to do this is the Code. While the Code could set out each individual standard, SA Power Networks considers it would be more flexible for the Code to authorise SA Power Networks to publish the applicable standards from time to time. To protect customers the Code could provide the standards must be consistent with:

- The standards set out in the Model Standing Offer for small generators approved by the AER; and/or
- SA Power Networks Service and Installation Rules.

A provision in the Code could also allow extension of SA Power Networks fixed and flexible export scheme to small generators. Currently that scheme will only apply to the customer who accepted the Model Standing Offer. This limitation restricts the ability to effectively role out that scheme. We note such a scheme is contemplated by rule 147A(1)(h) of the National Energy Retail Rules (but the scheme is to be prescribed at a jurisdictional level not a national level).

These changes will plug the identified regulatory gap as the requisite technical standards will extend to all small generators and not just those still owned by the original person who accepted the Model Standing Offer. The AEMC in discussions with SA Power Networks relating to the development of rule 147A made it clear that it was willing to make allowance for a range of technical requirements within the DSCC and 147A provided the technical requirements had an enabling jurisdictional instrument.

SA Power Networks therefore suggests a clause along the following lines:

"(a) The distributor may from time to time publish on its website technical standards with which small generators are required to comply provided those standards are consistent with one or more of:

(i) the standards set out in a Model Standing Offer approved by the Australian Energy Regulator under the National Electricity Rules;

(ii) the Service and Installation Rules of the distributor; and

(iii) any other requirements applying under South Australian law.

(b) The standards published under paragraph (a) may without limitation deal with export limits of small generators, testing intervals and requirements, protection elements, voltage and frequency requirements and any matter referred to in rule 147A of the National Energy Retail Rules.

(c) The distributor may from time to time publish the terms of a fixed or flexible export scheme into which small generators may opt in and the safety and technical requirements (including export limitations) with which a small generator who has opted in (and any subsequent owner of that small generator) must comply. Any such scheme must be consistent with the scheme set out in the Model Standing Offer approved by the Australian Energy Regulator under Chapter 5A of the National Electricity Rules or with any other scheme approved by the Commission.

(d) Standards published under paragraphs (a) or (c) above constitute applicable standards for the purposes of clause 6.6(a) of the Deemed Standard Connection Contract in Schedule 2 of the National Energy Retail Rules and safety and technical requirements for the purposes of rule147A of the National Energy Retail Rules."

3.3.C.4 Small Generators – Management

The growth of small generators has provided considerable benefits but also poses a number of challenges for the network. As is well documented, one of these challenges is how to manage the network where generation from small generators is greater than demand.

SA Power Networks submits it would be useful for the Code to expressly acknowledge that SA Power Networks may employ appropriate strategies to manage this scenario. This would make clear that the regulatory environment permits these strategies. SA Power Networks notes it does not employ these strategies to derive any benefit for itself. The strategies are employed to maintain security of supply and the integrity of the network.

SA Power Networks also considers it would be preferable to make clear SA Power Networks may interrupt or disconnect small generators who do not comply with the technical standards applicable to small generators. The inclusion of such a provision is contemplated by clause 10.5 and 12.1 of the deemed standard connection contract which allows interruption/disconnection where permitted by jurisdictional energy laws.

To give effect to the above, SA Power Networks submits provisions along the following lines should be included in the Code:

"Where the distributor, in good faith, considers the level of electricity being exported to the distribution network by generators for a period is posing a threat to the security or integrity of the distribution network, the distributor may take appropriate steps to address that threat including temporarily increasing the voltage of the distribution network or taking other steps consistent with good electricity industry practice."

"Where a small generator is not complying with the technical or safety standards applicable to that small generator and the distributor considers this poses a threat to the distribution network, property or of personal injury the distributor may interrupt or disconnect the small generator until the non-compliance is remedied. In such circumstances the distributor must, if requested by the small generator, notify them of the reason for the interruption or disconnection and of the steps required to address the non-compliance".

4. MINIMUM SERVICE RELIABILITY STANDARDS

4.1 Reliability service standard framework

In 2020 the reliability framework was extensively reviewed for the 2020-2025 RCP where it was decided to:

- Establish reliability standards based on feeder categories[18] not regions[19];
- Set targets for USAIDI, USAIFI and Customer Restoration of Supply (by two) for each feeder category; and

[18] There are four feeder categories which are CBD, Urban, Short Rural and Long Rural.

[19] The Commission is its SA Power Networks reliability standards review – Draft decision (August 2018) for the 2020-25 RCP.

- Monitor the regional reliability for the 10 regions,

We understand the Commission is not proposing to revisit the reliability framework at this time, as it has only been in operation for a few years.

SA Power Networks agrees that the reliability framework does not need amendment for the 2025-2030 RCP.

4.2 Customer expectations for reliability in Adelaide's CBD

The Commission made the following statements in its Issues Paper about Adelaide's CBD:

"SA Power Networks did not meet its CBD feeder performance targets for the duration and frequency of interruptions in 2017-18, 2019-20, and 2020-21, and did not meet its performance targets for network restoration in 2020-21. While the Commission found SA Power Networks had applied its best endeavours in meeting the network reliability standard for 2017-18 and 2018-19, the Commission is monitoring SA Power Networks' quarterly performance for potential longer-term trends or systemic issues. SA Power Networks' performance against this service standard is a focus area for the Commission and it expects SA Power Networks to be using its best endeavours to meet the service standard.

Recent performance in the CBD has been affected by issues including faults on different types of underground cables and construction damage.[20] Although the individual incidents have not had the same specific cause, the underground cable network in the CBD is aging, with some assets approaching the end of their expected lifespan."

The Commission is seeking stakeholder responses to the following question.

***Question for stakeholders**:*   *What are customers' expectations of reliability in the CBD? How are they different to expectations about other parts of the network?*

The Adelaide Central Business District (CBD) continues to be a key economic and cultural hub for South Australia. It supplies the needs of more than 100 thousand people living and working in the core CBD area. Power outages in the CBD have the potential for significant economic impact and understandably cause heightened frustration and inconvenience for business customers and the people living and working in the CBD.

Given these factors, customer and community expectations of the reliability of the electricity supply in the CBD are high, expecting significantly better reliability in the CBD than in other suburban areas of Adelaide or other areas of the State.

SA Power Networks has compared the reliability of CBD feeders in the National Energy Market in other mainland states and South Australia. The Table below highlights the recent five-year average[21] performance and the reliability standards that apply to CBD feeders.

[20] Information about SA Power Networks' historical performance outcomes for each regulatory year is available at: ESCOSA - SA Power Networks' historical performance outcomes. SA Power Networks' 2021 fact sheet 'Maintaining reliable and cost-effective electricity supply for Adelaide's CBD' is available at: Maintaining reliable and cost-effective electricity supply for Adelaide's CBD (sapowernetworks.com.au)

[21] Average financial year performance with last year being 20020-21. Melbourne average performance is calendar years 2016 to 2019 and financial year 2020-21.

Capital City	Avg. USAIDIn	Avg. USAIFI	USAIDI Target	USAIFI Target
Brisbane	1.8	0.019	15	0.15
Sydney[22]	15.2	0.055	45	0.30
Melbourne	8.5	0.115	8.9	0.108
Adelaide	24.8	0.187	15	0.15

The Table highlights that the USAIDI and USAIFI targets of other capital cities' CBDs are similar to those of Adelaide. However, actual recent performance of the CBD feeders in Adelaide compares unfavourably. The poorer performance of the Adelaide CBD feeders is mainly due to:

- 'one-off' events (eg third party damage); and
- cable faults in aging cables.

SA Power Networks normal strategy associated with cable failures is to replace a section of cable once two cable faults have occurred in that section. Two failures is a good indicator that the cable is in a poor condition and needs replacement. However, CBD cables that fail tend to be random one-off cable faults in different sections.

SA Power Networks is concerned that as these aging cable failures result from the cable's poor condition. Unless the age profile of cables in the CBD is addressed, the reliability of the CBD will gradually decline. SA Power Networks has engaged an expert cable consultant to assist us with developing an efficient targeted replacement programme to address the aging cables within the CBD. A proactive long-term replacement plan needs to be developed to address the declining reliability of CBD feeders. Subject to stakeholder support and funding approval, the replacement plan should commence in the next reset period (ie 2025-30 RCP) and address declining performance. The plan would likely span several reset cycles, to spread the cost. We will consult with customers on our planned approach as part of our 2025 Reset engagement program.

SA Power Networks will also be investing in 'self-healing' networks[23] within the Adelaide CBD to mitigate the effects of cable faults in the CBD. However, self-healing networks are reliant on other healthy cables to transfer load and customers once a cable fault has occurred.

SA Power Networks recommends maintaining the current reliability targets (ie on average we achieve those targets) are appropriate on the basis that they are the same as the Brisbane CBD and reflect the average historic performance of Sydney's CBD and are slightly worse than Melbourne's CBD. If CBD targets were set based on the current historic 10 years performance the USAIDI targets would be 18 minutes (ie a 20% worse target). We consider that a USAIDI target of 15 mins is appropriate for the CBD. This should permit us to propose a longer-term efficient replacement programme for the older cables in the CBD.

[22] Sydney's targets are minimum service targets (ie performance cannot exceed that target) and not average performance targets like the other capital cities.

[23] This will involve installing automated switching devices to transfer customer load from a faulted network section to an alternative cable supply

SA Power Networks proposes to specifically engage with customers on the reliability of the CBD and what replacement programmes are required to achieve and acceptable level of reliability.

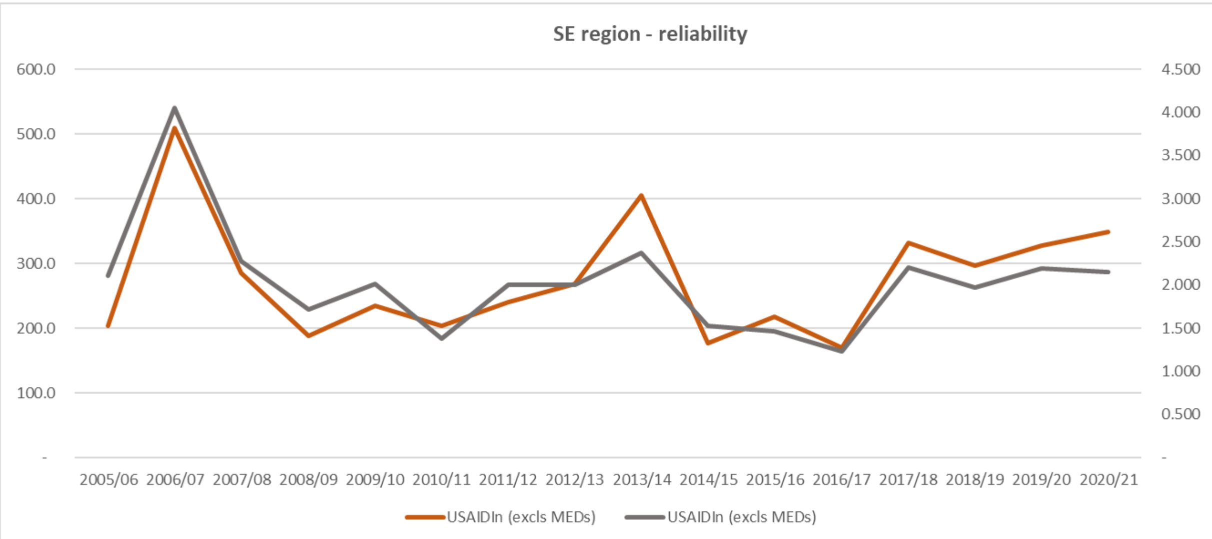
4.3 Regional Reliability

The Commission has expressed concern that in setting reliability targets based on feeder categories (ie CBD, Urban Short Rural and Long Rural) that regional reliability performance may decline. Consequently, the Commission monitors the reliability performance of ten geographic regions which are:

- Adelaide Business Area (ABA the same as the CBD feeder category)
- Barossa Mid-North and Yorke Peninsula (BMY)
- Eastern Hills (EH)
- Eyre Peninsula (EP)
- Fleurieu Peninsula (FP)
- Greater Adelaide Metropolitan Area (GAMA)
- Riverland and Murraylands (RM)
- Southeast (SE)
- Upper North (UNE), and
- Major Regional Centres (MRC eg Pt Augusta)

SA Power Networks has either maintained or improved the reliability performance for most of these regions except ABA (see discussion on CBD above) and possibly the SE region. Figure 1 below highlights a step deterioration in performance for the last four years. This step change has been due to several factors including non-systemic faults, possums and a gradual deterioration in the condition of some parts of 33kV subtransmission system that supply the SE.

Figure 1 - Southeast region normalised reliability (excludes MEDs)



SA Power Networks has been investing in its infrastructure in the SE over the last few years to address some of these problems. However, we are forecasting a step change in expenditure in the SE to address the condition of some parts of the 33kV sub-transmission network.

Further, there is evidence that a colony of grey headed flying foxes (bats) is being established in the SE. These bats are causing many outages in the GAMA, which we are partially addressing by investing in self-healing networks and covering our infrastructure near our poles to prevent, mitigate outages caused by bats. We expect that as the SE bat colony grows, we will be required to invest, at greater than historic levels, in our infrastructure to address this new cause of outages in the SE.

4.4 Consumer protections for Stand-Alone Power Systems (SAPs)

The Commission has posed the following question:

> ***Question for stakeholders**:*
>
> *Are there practical issues that exist in applying existing minimum network reliability standards and the Guaranteed Service Level (GSL) payments in SAPS?*

A recent amendment to the energy laws permits distributors to move customers off-Grid[24] and supply those customers from a regulated standalone power system (SAPS). Distributors are only permitted to take customers off-Grid where it is more efficient (ie lower whole of life cost to supply those customers using a SAPS than maintaining/replacing the powerlines that supply those customers). These types of SAPS are referred to as distributor-led SAPS (or regulated SAPS).

One of the energy laws SAPS amendment objectives was that customers who are shifted off-Grid to a distributor-led SAPS are treated as though they are still connected to the Grid. They still receive the same National Energy Customer Framework protections and purchase electricity from their chosen retailer. Consequently, we consider that customers connected to a distributor-led SAPS should be included in the Commission's Guaranteed Service Level Payments scheme.

Under the amendment to the energy laws, a distributor must develop and publish its:

- SAPS performance and supply standard[25];
- SAPS customer engagement document that sets out its SAPS customer engagement strategy[26].

For the existing minimum network reliability standards to apply to SAPS customers, the SAPS customers would need to be allocated to a feeder category. We would suggest that SAPS customers be allocated to the feeder category that they were allocated to, immediately prior to those customers being moved off-Grid. Alternatively, as SAPS customers are likely to be at edge of our distribution network, they could all be allocated to the Long Rural Feeder category.

Under the SAPS energy laws SA Power Networks must publish its SAPS performance and supply standard. That standard will detail the performance and the quality of supply customers will receive if supplied from a distributor-led SAPS. The SAPS performance and supply standards must have regard to the SAPS quality of supply principle. The principle means "the principle that the quality and reliability of supply experienced by a Distribution Customer having a connection point with a regulated SAPS should be no worse than the quality and reliability of supply that the Distribution Customer would experience if the connection point were in a part of the distribution network forming part of the interconnected national electricity system". In accordance with the NER Rule 5.13B.1, distributors

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24 Off—Grid means the customer is not supplied via the distribution network forming part of the interconnected national electricity system.

25 NER Rule 5.13B.1

26 NER Rule 5.13B.2 a distributor must develop a strategy (SAPS customer engagement strategy) for engaging with affected network users in relation to distributor-led SAPS projects being considered by the distributor in relation to the network.

are required to comply with its published SAPS performance and quality of supply standards. So, the energy laws ensure that customers who are supplied from a regulated SAPS will receive no worse performance than those like customers connected to the Grid.

SA Power Networks is not envisaging moving many customers off-Grid during the current or next regulatory control period, to supply them via a SAPS.

5. Network planning criteria

5.1 SA Power Networks internal planning criteria

SA Power Networks undertakes network planning to ensure that:

- The forecast peak demand with 10%, 50% Probability of Exceedance (PoE) and minimum load on the network is supplied within regulated standards without exceeding the thermal or fault rating of any network or connection point assets for either the import or export;
- The utilisation of network assets is optimised; and
- The design and scheduling of network augmentation projects minimises the overall costs, maximises benefits, meets regulatory obligations and reasonable customer expectations, while maintaining existing levels of reliability and security of supply arrangements.
- The distribution network is resilient to high impact low probability (HILP) events so that large numbers of customers do not experience excessively long unplanned outages.

SA Power Networks has developed, over decades, deterministic network planning criteria (our Planning Criteria) to guide when the distribution system should to be augmented (ie capacity to deliver or accept energy is increased). Our Planning Criteria deliver an efficient risk minimisation for customers to not experience excessively long outages when a HILP event occurs. The distribution system, due to being augmented in accordance with our Planning Criteria, currently includes an accepted level of resilience to cope with HILP events. In our engagement with customers, they have agreed that a degree of resilience should be incorporated in our distribution network.

Most other distributors in the NEM also have output standards (eg reliability standards) to achieve. Many of those distributors use a probabilistic network planning approach to achieve those standards. In simplistic terms, a probabilistic approach to network planning determines whether the annual cost of unserved energy (ie the benefit to customers) exceeds the annualised cost of network augmentation and if so the augmentation should occur. The investment will be made in the year prior to the annual benefit exceeding the annualised cost.

A probabilistic network planning approach should meet output standards but will not typically mitigate the impacts of HILP events. Despite the unserved energy being significant the low probability of a HILP event typically means the customer benefit of preventing the event does not exceed the cost of the preventing the event.

The AER recognised the potential impacts of HILP events (referred to as Widespread and Long Duration Outages (WALDO)) and tried to develop a VCR for those events to assist distributors and transmitters to efficiently augment their respective networks to mitigate those events. However, the AER decided to discontinue the project (in September 2020).

Some jurisdictions specified input standards (similar to our deterministic network planning criteria) for compliance by distributors. Queensland distributors currently have 'safety net standards' which are similar to high level input standards (see Table 2 for Energex's Safety Net Standards).

The Queensland jurisdictional safety net standards provide guidance on when the distribution network in Queensland should be reinforced to prevent HILP type events.

"The purpose of the service safety net, applicable from 1 July 2014 onwards, is to seek to effectively mitigate the risk of low probability high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption."

The safety net targets for Energex are:

Table 2 - Energex Distribution Authority Safety Net Standards.

Feeder category	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban – Following an N-1 event	• no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • no greater than 12 MVA (5,000 customers) is without supply for more than 3 hours; and • no greater than 4 MVA (1,600 customers) is without supply for more than 8 hours.
Short Rural – Following and N-1 event	• no greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • no greater than 15 MVA (6,000 customers) is without supply for more than 4 hours; and • no greater than 10 MVA (4,000 customers) is without supply for more than 12 hours .

Note: All modelling and analysis will be benchmarked against a 50% PoE loads and based on credible contingencies.

NSW distributors had a Security Standard until 1 July 2015, but now just have output standards. Victorian distributors are required to use 'best endeavours' to comply with the reliability targets contained in their revenue determinations. In addition, Victorian distributors have the following best endeavours obligation, contained in the Victorian Distribution Code (clause 3.1(c))

"develop, test or simulate and implement contingency plans (including where relevant plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on customers."

SA Power Networks engaged Cutler Mertz to prepare a report (executive summary attached) which compares deterministic and probabilistic approaches to network planning. Cutler Merz determined that our internal deterministic planning approach has similar outcomes (ie augmentation of the network) to using a probabilistic approach until the end of the next reset period (ie 2030). They advised:

"The modelling demonstrates that SA Power Networks' current deterministic input standard is considerably less onerous than the Safety Net and Security Standard input standards, and interestingly, is likely to result in investment similar to that, if a probabilistic approach were to be implemented. This could be because the current deterministic criteria have been set at a reasonably conservative level (i.e. N-1 is not required to the level as in other DNSPs) and SAPN's emergency ratings are well in excess of nameplate values."

Further they recommended that we engage with the Commission on codifying our current deterministic standard (or a simplified variant thereof) to provide a regulated safety net for customers. This is based on the following statement:

"It is recommended that SA Power Networks work to codify a customer Safety Net target, to alleviate the adverse outcomes of low probability, high consequence events. The current deterministic standard, or a simplified variant thereof, should be used as the basis of developing the Safety Net target.

In changing the approach to capacity planning from an internal deterministic standard to a probabilistic, VCR based, consideration needs to be given to the expectations of customers with respect to the security afforded to them for high consequence events. Providing constancy between regulatory periods, both from an investment and network performance perspective is an important consideration.

The outcome of adopting a strictly probabilistic approach is that there is no security of supply for outages that are consequential but have a low likelihood of occurring. SA Power Networks' current planning standards recognise this risk and have formed the basis of capacity augmentation for previous regulatory periods. The adoption of a strictly probabilistic approach is likely to increase risks to SA Power Networks' customers over the long term as the protection (i.e. risk mitigation) afforded by the current planning standard is removed. A codified Safety Net target would provide customers with such protection."

SA Power Networks would like to work with the Commission and our customers to determine if safety nets could be included in the Code to minimise the impacts of HILP and maintain augmentation expenditure at similar historic levels to that resulting from our internal network planning criteria.

It must be noted that the AER is not required to including funding in its Distribution Determination for SA Power Networks, for us to continue to comply with our Planning Criteria. The AER is only required to include sufficient funding for us to comply with our regulatory obligations (eg Code reliability standards, Electricity Act technical and safety standards etc).

6. PUBLIC LIGHTING FRAMEWORK

6.1 Public Lighting services

SA Power Networks provides public lighting services for 67 public lighting customers throughout South Australia, including local councils and the South Australian Department of Infrastructure and Transport (DIT).

Public lighting improves the safety and amenity of our local communities through the supply, installation and maintenance of public lights across South Australia. There are approximately 230,000 luminaires / public lighting installations across our network. The delivery of public lighting services involves the ongoing maintenance, inspection, and operation of these public lighting installations.

Public lighting services also include the design, procurement and construction of new public lighting installations as requested by public lighting customers.

6.2 Public lighting service standard framework

The Commission has posed the following questions:

Question for stakeholders:

Does there continue to be a role for the Code in setting street light repair obligations?

Are the service levels in the Public Lighting Service Framework sufficient to ensure outcomes for public lighting customers, and consumers (residents, businesses and road users)?

The Commission currently has two roles in street lighting which are:

- Monitoring SA Power Networks streetlight repair performance; and
- Setting the Street Light Out (SLO) Guaranteed Service Level (GSL) payment regime.

6.3 The role of the Code in setting streetlight repair obligations

In collaboration with the Local Government Association of South Australia (LGA) a Public Lighting Working Group (PLWG) was established in late 2018. This PLWG was established as a representative body to facilitate a practical ongoing consultation with SA Power Networks. The PLWG is chaired by the LGA, and consists of representatives from metropolitan and regional councils, the DIT, and SA Power Networks.

In collaboration with the PLWG, SA Power Networks implemented a new Public Lighting Service Framework from 1 July 2020, outlining the target levels of service SA Power Networks aims to deliver to customers and stakeholders. These service levels, in conjunction with the service standards contained within the Code, formed the basis of SA Power Networks' 2020-25 public lighting pricing proposal.

SA Power Networks' performance against service levels is a regular agenda item at PLWG meetings, enabling direct conversations between PLWG members and SA Power Networks to ensure that SA Power Networks is taking the necessary steps to deliver the service standards expected by public lighting customers. SA Power Networks is working to implement new operational performance reporting as part of our public lighting customer portal, providing public lighting customers with our operational performance for their specific service area. These performance reports are expected to be available late in the current regulatory control period.

SA Power Networks has actively consulted with the PLWG members in an attempt to better understand their preferences for setting service standards for public lighting into the future. In preparation for the Commissions review of the Code, SA Power Networks facilitated discussions on the public lighting GSL scheme at the PLWG meetings on 18 August 2021, 24 November 2021, and 2 March 2022. A consultation paper was provided to PLWG members prior to the March meeting, detailing the current GSL requirements, our historical performance, the intended purpose of the GSL scheme, the transition to smart lighting and nature of the GSL schemes operating in other jurisdictions.

Following the Commissions release of its issues paper, a special meeting of the PLWG was held on 28 April 2022 with the Commission to discuss the Code review for public lighting. There were mixed views across the PLWG members, with some members wanting to retain the GSL scheme and other's suggesting the scheme is no longer required. Noting these variations, SA Power Networks released a short survey to PLWG members to ascertain their views on:

- The ongoing involvement of the Commission in setting service standards beyond 2025; and
- The retention and structure of the GSL scheme.

Unfortunately, we only received one response to this survey, with this respondent supporting the Commissions continued involvement in setting service standards.

A further meeting of the PLWG was held on 25 May 2022, this meeting focussed on the Commissions ongoing involvement in setting service standards for public lighting. Three options were considered:

1. The Commission continues to set service standards and monitor performance;
2. The commission continues to monitor performance with service levels agreed between SA Power Networks and public lighting customers; and
3. The Commission no longer has a role in setting service standards or monitoring performance.

The ability for SA Power Networks to effectively agree service standards with public lighting customers was considered. While the PLWG is an effective advisory group, broader consultation with all public lighting customers would be required. We note from the discussions within the PLWG, that the views of individual public lighting customers on the service standards are varied. This is likely to make reaching a consensus on the application of consistent service levels across the sector challenging. Therefore, the PLWG expressed a preference for Option 1, for the Commission to continue to set service standards and monitor SA Power Networks ongoing performance.

Noting the continued development in public lighting technology, particularly the introduction of smart lighting, we recommend that the Commissions involvement should be reviewed again prior to the 2030-35 regulatory period.

The PLWG acknowledged there are issues with the current GSL scheme and supported a detailed review of the scheme, including the structure and application of the GSL scheme.

6.4 Issues with current Code SLO GSL regime

6.4.a What guaranteed times should apply to streetlight repairs?

The GSL scheme contained in the Code detailed two repair times for streetlight repairs being:

- five business days for lights in Metropolitan Areas (ie Greater Adelaide Area and major regional cities); and
- ten business days for lights in Other Areas.

A payment is made to the first person who reports the streetlight out with a $25 payment for each period (five or ten business days depending on its location) in which the light is not repaired. For example, if it takes 16 business days to repair an SLO in a Metropolitan Area the customer would receive a $75 payment.

GSL payments provide an incentive for:

1. customers to report an SLO on the basis that they may receive a GSL payment (noting that only 7% of SLO reports receive a GSL payment); and
2. for SA Power Networks to repair the streetlight as soon as practical.

There are two classes of faults that result in a SLO, which are:

- Simple/general faults (e.g. Globe within the streetlight has failed); and
- Complex faults (e.g. fault in the underground cable supplying the streetlight).

It is practical to attend a streetlight and repair a simple fault within five business days, but it is not practical or efficient to repair a complex fault within five business days. When an SLO is reported, a crew will attend to determine the nature of the fault (e.g. that it is a simple or complex fault). Simple faults will generally be repaired on the initial site visit. For complex faults, it may take multiple visits to locate the cause of the fault and then repair it. Further, it may require access to private property to repair the fault, where we are required to give reasonable notice of the entry (typically two weeks notice). In 2020/21, rectification of SLO's associated with cable faults took an average of 23 business days[27].

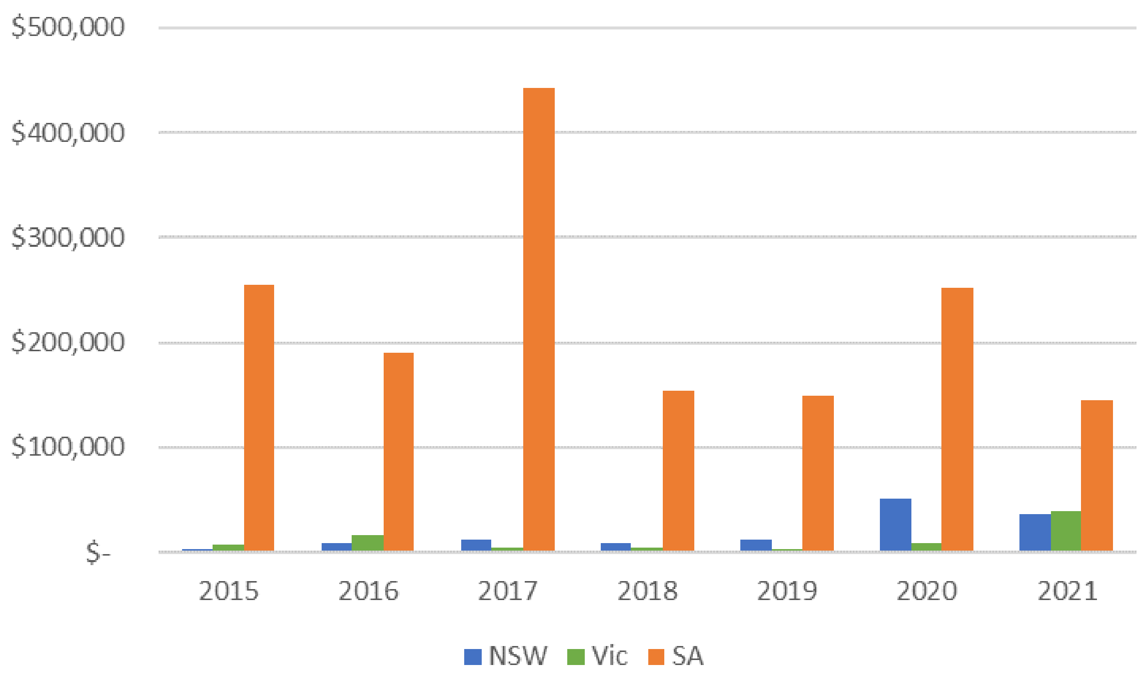
The NSW streetlight regime recognises that different classes of faults can result in different repair times. It classifies streetlight faults into 'general' and 'complex' faults, providing the distributor with 10 business days to repair a general fault and 30 business days to repair a complex fault. If the distributor exceeds these repair times the first person[28] to report the SLO receives a single $25 GSL payment.

SA Power Networks considers that repair times for streetlight repairs and the associated GSL payment need to reflect the different classes of faults. The current SLO GSL regime of applying a single repair timeframe to all SLO faults and the inclusion of multiple payments, is costing about an additional $1M over a regulatory control period when compared to the GSL regimes operating in other jurisdictions. Distributors report GSL payment data each year to the AER as part its Regulatory Information Notice, annual payments reported for New South Wales, Victoria and South Australia for the past 7 years is presented in Figure 2 below.

[27] SA Power Networks was penalised more than $29,000 for the repair of 317 cable faults, within an acceptable repair time.

[28] The first person with a premise that abuts the streetlight or a public lighting customer (eg Council to whom the distributor is providing streetlighting services).

Figure 2 - Annual GSL Payments in New South Wales, Victoria and South Australia



SA Power Networks considers that if the GSL regime in South Australia provided a single GSL payment of $25 where a streetlight was not repaired in the guaranteed time, it would reduce the cost of the SLO GSL scheme by more than $0.6m over the regulatory control period. Removal of the multiple payments would reduce the costs to SA Power Networks and ultimately all public lighting customers.

SA Power Networks will be consulting with public lighting customers in 2022 on what type of GSL regime should apply to the 2025-30 regulatory control period.

6.4.b Do the current SLO GSL payments provide the right incentive?

Table 3 below compares SLO repair times in jurisdictions with a SLO GSL regime. The South Australian regime has similar repair performance to New South Wales and Victoria. We note, these jurisdictions do not have multiple payments for a SLO and limit the SLO GSL payment to customers with premises adjacent to the streetlight.

Table 3 - Average performance over 2019/20 and 2020/21

	SA	NSW	Vic
Average SLO repairs times (business days)	5.1	6.1	3.2
Average no. GSL payments	1,890	1,757	780

Source: AER Annual RIN data

The current South Australian streetlight GSL payment regime also provides an incentive for 'serial' reporters to maximise GSL payments by:

- ‘dumping’ large numbers of SLOs (we have experienced 40 or more) in a single night/report; and
- reporting working streetlights as an SLO[29].

This behaviour overwhelms our ability to respond efficiently and repair genuine SLOs reported within the specified guaranteed time. In 2020-21 more than 15% of SLOs reported by serial reporters were found to be working when we attended to make repairs. This is compared to less than 3% of SLOs for other SLO reporters (ie who report 2 or less SLOs each year). This highlights a perverse incentive within the current scheme for serial reporters to report working streetlights as an SLO, resulting in inefficient costs to SA Power Networks and ultimately all consumers.

6.5 Conclusion

Our analysis has demonstrated that the current South Australia SLO GSL regime as detailed in the Code creates significant additional costs, ultimately born by public lighting customers and their ratepayers (ie electricity consumers). The SLO regime provides no additional benefit to ensure that streetlights are working, when compared to the SLO GSL regimes that operate in other jurisdictions (ie NSW and Victoria).

Following consultation with public lighting customers, we support the Code continuing to specify streetlight repair obligations for the 2025-30 regulatory period. The structure and application of the GSL scheme should be reviewed. Where a GSL scheme is to be retained, SA Power Networks supports consideration of general and complex faults in setting timeframes for SLO repairs and removal of the multiple payments for a single SLO. We will continue consulting with public lighting customers on the structure and application of the GSL regime for the 2025-30 regulatory control period.

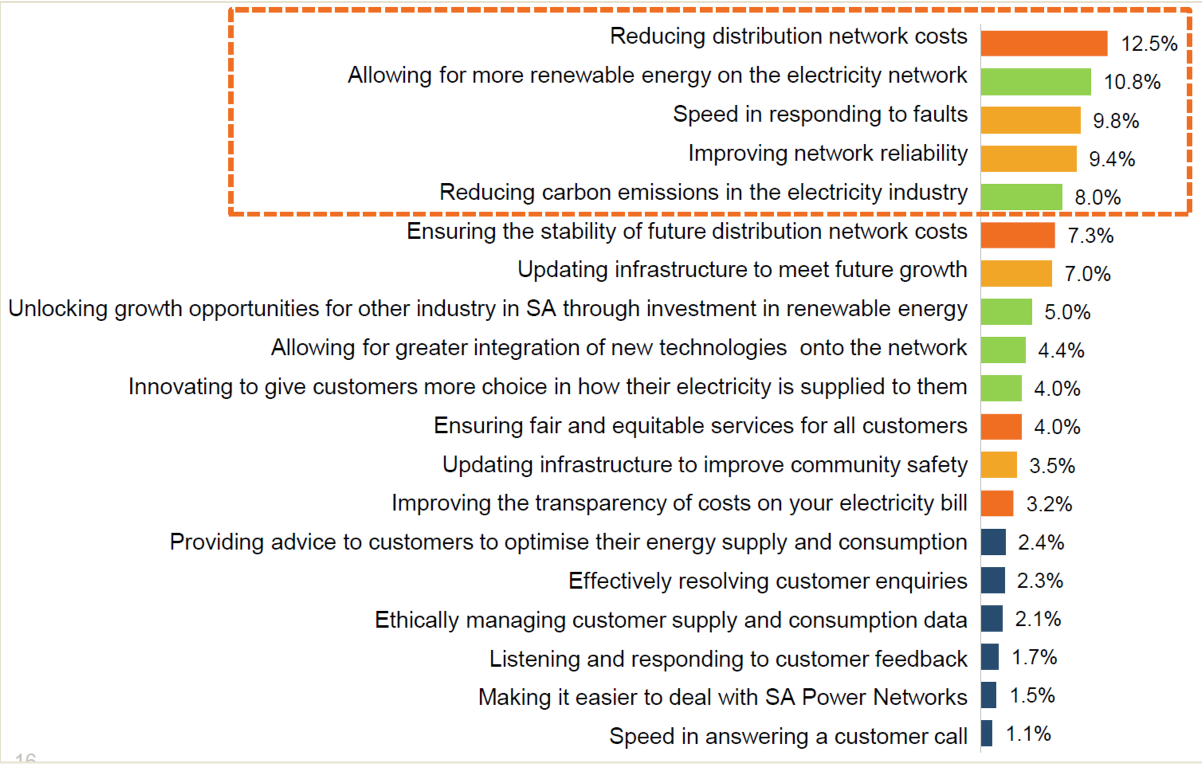
Further, we consider that the Commission should continue to have a monitoring role, to ensure that we are continuing to appropriately maintain streetlights and promptly repair streetlight faults. We recommend that the Commission’s involvement in setting streetlight repair obligations and monitoring our performance against these standards should be reviewed again prior to the 2030-35 RCP.

[29] In calendar year 2018 and 2019 a serial reporters reported 1,000 SLO of which 28% were found to be working when attended. The serial reporter was paid $9,000 in GSL payments but cost nearly $25,000 to attend working streetlights. These crews could have attended and repair streetlight which were not working. In calendar years 2018 and 2019 14% of SLO reports were for working streetlights, which cost in in excess of $0.6m to attend.

7. Customer service measures

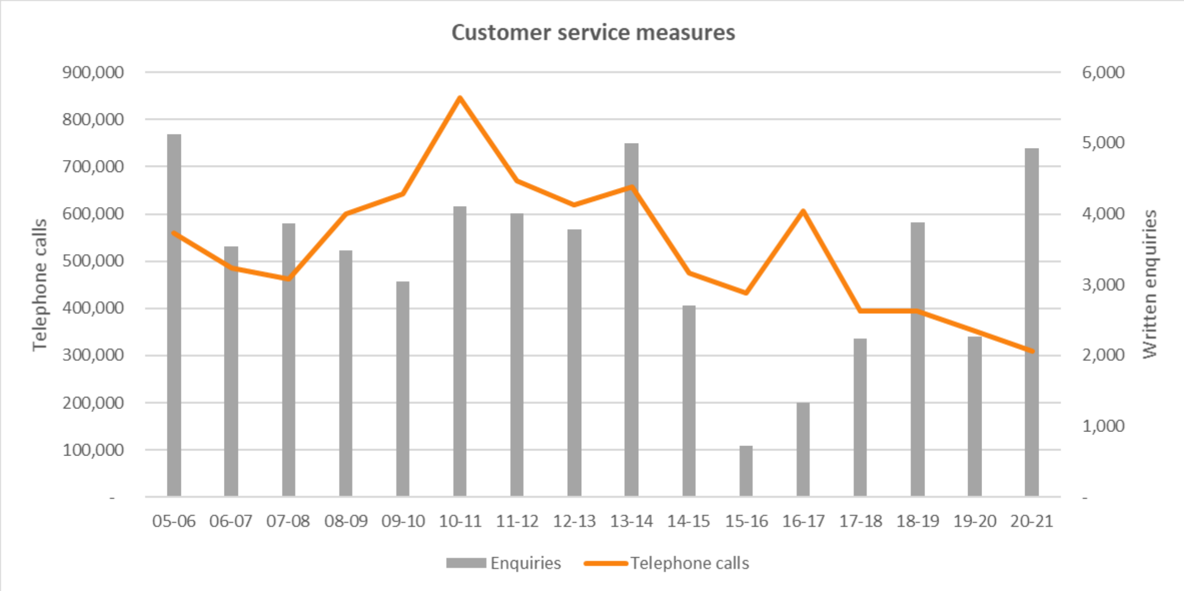
SA Power Networks expressed concern during the process for setting the customer service measures for 2020-2025, that the current measures may have become less relevant for customers. The main measure of concern is answering a telephone call within 30 seconds[30], which was rated as least important to customers in a recent piece of quantitative customer research that asked customers to rank in order of importance a range of different service attributes (Figure 3). Figure 3 indicates a significant reduction in the number of telephone calls SA Power Networks received from customers since 2005-06. The number of written enquiries (which now include social media enquiries) from customers has significant annual variation but appears to still be relevant for customers, with social media increasingly becoming a channel of choice for customers to contact SA Power Networks.

Figure 3 - Customer research findings on what customers value



30 The service attribute was “speed in answering a customer call”.

Figure 4 - Current Code customer service measures



Since 1 April 2018 we have been measuring additional customer satisfaction measures, and have been reporting these to the Commission since 1 July 2020 which focus on how effectively we communicate with customers in the following areas:

- Planned interruptions
- Unplanned interruptions
- New connections
- General Enquiries, and
- Customer complaints.

These measures are based on surveys of customers who have experienced those interactions in the past month. There are several distributors which are also using these monthly customer satisfaction measures, so we can compare our performance with other distributors.

As discussed above, recent customer research reveals that speed in answering telephone calls is now less valuable to customers. SA Power Networks considers that customers getting their query/enquiry/compliant resolved at the first contact (eg telephone call) is more reflective of current customer expectations and priorities, and that customers would be willing to wait longer if their call was resolved at the first contact. Consequently, at the beginning of 2022 we commenced measuring customers' satisfaction where the query was resolved, whether in their favour or not. These calls take longer and consequently contribute to our declining performance in responding to telephone calls within 30 seconds (having said that, we continue to meet the current target).

SA Power Networks is about to commence engagement with customers on preferred customer service measures and whether answering telephone calls in 30 seconds remains a priority, or whether a measure of customer satisfaction or first enquiry resolution is more valued by customers. We also intend to explore customers' communication channel preferences and trends and investigate whether there is merit in focussing on emerging channels such as social media and other digital platforms, and can provide the Commission with further data on this as required. We will keep the Commission informed of the outcomes of our engagement which we expect to be complete by early 2023.

AUGEX Economic Modelling and Supporting Evidence for SAPN Regulatory Submission 2025-2030

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1.0	Draft report	RD	RK	RD
2.0	Updated report incorporating SA Power Networks comments	RD	RK	RD
3.0	Final report	RD	RK	RD

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Acronyms and Abbreviations

Table 1: Acronyms and Abbreviations

Term	Definition
Augex	Augmentation Expenditure
DAPR	Distribution Annual Planning Report
DTAPR	Distribution and Transmission Annual Planning Report
DNSP	Distribution Network Service Provider
CAIDI	Customer Average Interruption Duration Index
EDC	Electricity Distribution Code
EDL	Electricity Distribution Licence
ESCOSA	Essential Services Commission of South Australia
GSL	Guaranteed Service Level
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
N	System normal
NSW	New South Wales
QLD	Queensland
RCES	Restoration of customer's electricity supply
SA	South Australia
SAIDI	System Average Interruption Duration Index (assumes planned outages are excluded)
SAIFI	System Average Interruption Frequency Index (assumes planned outages are excluded)
SAPN	South Australian Power Networks
STPIS	Service Target Performance Incentive Scheme
TAS	Tasmania
TMU	Target Maximum Utilisation
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
USE	Unserved energy is the expected energy at risk at not being delivered to customers
VCR	Value of Customer Reliability

Figures

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Executive Summary

Distribution network operators are responsible for planning, designing, operating and maintaining their network to achieve an optimum mix between capital and operational expenditure, and the desired level of security and quality – that is, reliability.

In the National Electricity Market (NEM), the regulation of distribution reliability is implemented through a set of Codes and other such requirements specific to each jurisdiction. Primarily, the requirements are in the form or either input or output standards, or both.

Output standards are targets of reliability performance that DNSPs need to achieve. The standards are primarily expressed in the form of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) and can be set at a whole of network level, feeder category, individual feeder, or individual (large) customer. All NEM jurisdictions have output standards, with most being set within the relevant Code, Licence or Authority. The exception to this is Victoria and the ACT where the DNSPs are able to set their own targets.

Input standards refer to specific criteria for how a DNSP should plan the capacity in their network. These standards are primarily expressed as minimum outage durations for loads above a determined size, such as "less than X MW of load may be disconnected for more than Y minutes/hours". Queensland is the only jurisdiction that sets an input standard. Between 2005 and 2015, NSW also had an input standard that specified the design planning requirements for network capacity. Whilst input standards are less common, all DNSPs utilise an internal input standard for identifying areas and elements in the network that should be targeted for reliability investigations.

SA Power Networks is one such network that has an output standard (SAIDI and SAIFI targets) outlined in the Distribution Code and has developed an internal input standard against which network capacity is planned.

SA Power Networks engaged CutlerMerz to review the network capacity planning approaches being implemented by DNSP counterparts in the NEM and consider whether there would be value in adopting an alternative capacity planning standard, most notably, a probabilistic approach to achieving the codified output standard.

Reliability (capacity) planning standards

Table 2 summarises the jurisdictional standard and the approach to meeting the standard that is used by NEM DNSPs within that jurisdiction. It is noted, that as a matter of practice, all DNSPs use a deterministic, N-1 approach as an internal guideline for identifying parts of the network where capacity augmentation may be warranted.

Table 2: Planning standards applied by NEM DNSPs

Scenario	Jurisdictional standard	Approach to planning
Queensland	Output and input standard. SAIDI and SAIFI targets set in the Distribution Authority Safety Net (N-1) requirements set in the Distribution Authority	Deterministic to achieve the Safety Net, otherwise probabilistic.

Scenario	Jurisdictional standard	Approach to planning
NSW	Output standard SAIDI and SAIFI targets set in the distribution licence	Probabilistic
Victoria	Output standard SAIDI and SAIFI targets agreed between the DNSP and the AER and in price determinations	Probabilistic
South Australia	Output standard SAIDI and SAIFI targets set in the Code Restoration time targets set in the Code	Deterministic
Tasmania	Output standard SAIDI and SAIFI targets set in the Code	Deterministic
ACT	Output standard SAIDI and SAIFI targets set by the DNSP against minimum targets in the Code	Probabilistic

In jurisdictions that adopt a deterministic approach to meeting the jurisdictional standard, the process involves:

- Defining and documenting criteria (input standards) for where network redundancy is required (i.e. N-2, N-1 or N levels of security)
- Assessing N-2, N-1 and N ratings against forecast maximum demand for several years into the future (e.g. PoE 50 demand forecast for 5 years);
- For network elements that fail the assessment (after load transfers and allowable outage restoration time), delivering network augmentation (or non-network) solutions prior to the year that the element would breach the requirement.

In jurisdictions that adopt a probabilistic approach to meeting the jurisdictional standard, the process generally involves:

- assessing N-1 and N ratings against forecast maximum demand (e.g. PoE 50);
- calculating "Expected Unserved Energy" in cases where the forecast maximum demand is greater than the element ratings;
- estimating the probability of an outage coincident with the forecast maximum demand ("probability weighted energy at risk");
- utilising the value of customer reliability (VCR) to estimate the expected cost of unserved energy
- evaluating the annual cost of unserved energy against the annualised cost of network augmentation to assess whether an investment has a benefit to cost ratio greater than 1.

It is apparent from historical evidence that in the case of a deterministic approach to planning, a conservative input standard can result in network expenditure being above that considered economic. Conversely, a probabilistic standard can fail to account for the absolute potential impact of an outage. Network investments to mitigate low probability events that have high consequences could be desirable for customers but may be unlikely to proceed because the quantification of risks and benefits shows them to be uneconomic.

Achieving the optimal balance between a strictly economic approach, and the additional risks that may result from this approach have been considered in Queensland through the inclusion of a Safety Net. The

Safety Net requirements are contained in the same regulatory instrument as the output standards (SAIDI and SAIFI targets) and effectively provide an input standard that sets an upper limit to the customer consequence (in terms of unsupplied load) resulting from an outage. Queensland DNSPs are required to achieve the standard to the extent reasonably practicable. In practice, this provides the DNSPs with the opportunity to exempt themselves from complying where they believe that the risk of failing to meet the standard is very remote, and therefore the investment to achieve the standard would not be considered good industry practice.

In Victoria, whilst there is not a deterministic "Safety Net", the Distribution Code requires DNSPs to develop, test or simulate and implement contingency plans (including where relevant, plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on customers.

Modelled scenarios and implications

To evaluate the impact of moving from the current approach to network capacity planning to an alternative, four scenarios were modelled:

1. SAPN Deterministic Criteria (Base case) – SA Power Networks current network capacity planning criteria
2. Probabilistic – economic investment where the benefits outweigh the costs
3. Qld Safety Net – the deterministic input standard (as applied by Energex) seeking to avoid low probability, high consequence events
4. NSW Security Standard – a deterministic input standard that applied in New South Wales from 2005 to 2015

The results were generated by considering what investment would (or may in the case of probabilistic) be required to increase the capacity at three network levels / elements to comply with the relevant standard to meet the demand forecast to 2029/2030. The result of the assessment are shown below:

Scenario	33kV sub-trans feeders[1]	Zone subs (transformers)[2]	HV feeders[3]
SAPN Deterministic Criteria	No feeders	1 substation	6 feeders
Probabilistic*	≤ 1 feeder	≤ 1 substation	≤ 13 feeders
Qld Safety Net	40 feeders	14 substations	0 feeders
NSW Security Standard	37 feeders	31 substations	4 feeders

* - assumes investment may be warranted but would depend on the cost of the option.

The modelling demonstrates that SA Power Networks' current deterministic input standard is considerably less onerous than the Safety Net and Security Standard input standards, and interestingly, is likely to result in investment similar to that, if a probabilistic approach were to be implemented.

Conclusions and recommendations

SA Power Networks' internally developed deterministic criteria and the approach to setting equipment ratings for use in the evaluation of the deterministic standard (i.e. emergency ratings considerably higher

[1] 287 33kV feeders were assessed
[2] 509 transformers were assessed
[3] 902 HV feeders were assessed (single customer feeders have been excluded from the assessment)

than the nameplate rating) result in a level of capacity investment that is broadly consistent with the outcomes that would result from a probabilistic approach to at least 2030.

However, the analysis also illustrated that adopting a strictly probabilistic approach does not recognise the full value of an incident (i.e. high consequence events). The modelling showed that there were several substations within the SA Power Networks system that have a high expected value of unserved energy after a failure, but as the probability of such a failure is low, it is not likely to be economically justified to improve redundancy. Despite the apparent high value of an incident, under SA Power Networks' current deterministic standard, the requirements to provide additional capacity has not been triggered, and therefore, the risk appears to be low from SA Power Networks' perspective.

In general, our analysis has found that the current deterministic planning criteria appears to provide for a degree of network capacity, slightly ahead of when a probabilistic approach would determine investment would be justified on a strictly economic basis.

In this regard, the current deterministic approach is effectively providing a quasi-safety net. It affords SA Power Networks' customers with a degree of "capacity inertia" whereby there is some level of protection from certain network outages.

Recommendations:

1. It is recommended that SA Power Networks adopt a planning standard that takes into account the Value of Customer Reliability (VCR)

   The results of the modelling indicate that moving to a probabilistic planning criteria would have minimal impact on SA Power Networks investment profile compared to the current deterministic standard through until 2030. Furthermore, in the absence of a jurisdictional standard providing the basis of a deterministic approach to capacity planning, the AER is unlikely to support investment an approach that is not probabilistic.

2. It is recommended that SA Power Networks work to codify a customer Safety Net target, to alleviate the adverse outcomes of low probability, high consequence events. The current deterministic standard, or a simplified variant thereof, should be used as the basis of developing the Safety Net target.

   In changing the approach to capacity planning from an internal deterministic standard to a probabilistic, VCR based, consideration needs to be given to the expectations of customers with respect to the security afforded to them for high consequence events. Providing constancy between regulatory periods, both from an investment and network performance perspective is an important consideration.

   The outcome of adopting a strictly probabilistic approach is that there is no security of supply for outages that are consequential but have a low likelihood of occurring. SA Power Networks' current planning standards recognise this risk and have formed the basis of capacity augmentation for previous regulatory periods. The adoption of a strictly probabilistic approach is likely to increase risks to SA Power Networks' customers over the long term as the protection (i.e. risk mitigation) afforded by the current planning standard is removed. A codified Safety Net target would provide customers with such protection.