Electricity

SA Power Networks reliability standards review

Draft decision

August 2018

Request for submissions

The Essential Services Commission (**Commission**) invites written submissions on this paper by **14 September 2018.**

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The Commission may also exercise its discretion not to publish any submission based on length or content (for example containing material that is defamatory, offensive or in breach of any law).

Responses to this paper should be directed to: **SA Power Networks reliability standards review – draft decision**

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Table of contents

Glossary of terms

ABA	Adelaide Business Area
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMA	Adelaide Metropolitan Area
CAIDI	Customer Average Interruption Duration Index
CBD	Central Business District
Code	Electricity Distribution Code version 12.1
Commission	Essential Services Commission, established under the Essential Services Commission Act 2002
Duration payment	Duration of interruption GSL payment
Electricity Act	Electricity Act 1996
ESC Act	Essential Services Commission Act 2002
Frequency payment	Frequency of interruption GSL payment
GSL	Guaranteed Service Level
IEEE	Institute of Electrical and Electronics Engineers
IVR	Interactive Voice Response
MAIFIe	Momentary Average Interruption Frequency Index
MECS	Monitoring, Evaluation and Compliance Strategy
MED	Major Event Day
MRC	Major Regional Centres
MWh	Megawatt hours
Ofwat	Economic regulator of the water sector in England and Wales
Review	SA Power Networks reliability standards review 2020
SACOSS	South Australian Council of Social Services
SRMTMP	Safety, Reliability and Maintenance Technical Management Plan

Street light payment	Repair of faulty street light GSL payment
SMS	Short Message Service
STPIS	Service Target Performance Incentive Scheme
SWE	Severe Weather Event
Total duration payment	Total annual duration of interruption GSL payment
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Frequency Duration Index
VCR	Value of Customer Reliability

Overview

This is the Essential Services Commission's (**Commission**) draft decision on the review of the reliability framework that will apply to SA Power Networks from 1 July 2020 to 30 June 2025 (**Review**). Through this draft decision, the Commission is seeking comment and feedback on its draft proposals by 14 September, with a view to making a final decision in December of this year (to take effect from July 2020).

The Commission's draft decision sets out that, for the 2020 – 2025 period, network reliability performance standards will apply to ten region-based categories. Targets will be set to maintain reliability at current levels, rather than improve or reduce performance.

This approach is supported by results of a customer survey showing that 73 percent of customers are satisfied with current reliability outcomes, and the results of economic assessments which show no clear economic benefit in setting targets to improve performance.

The draft decision proposes to replace current one-off duration of interruption Guaranteed Service Level (**GSL**) payments (**duration payments**) with total annual duration of interruption payments (**total duration payments**).

This approach is supported by evidence that duration payments are not focused on customers with ongoing, persistent reliability issues; that current levels of duration payments are not a strong driver of SA Power Networks' response to interruptions; and, customer survey results that indicate only 52 percent of customers are willing to pay for duration payments.

Further changes to the GSL scheme set out in this draft decision include: simplifying frequency of interruption GSL payments (**frequency payments**), removing GSL payments for late attendance at appointments, and removing GSL payments for repair of faulty streetlights (**street light payments**).

The Commission's draft decision proposes to introduce a requirement that information provided by Short Message Service (**SMS**) messages must be timely, current and accurate, and a requirement to monitor overall communication quality.

From 1 July 2020, SA Power Networks will be required to report directly to its customers on its reliability performance, both to fulfil regular reporting requirements and to provide explanations when it misses performance targets, and following significant events. This will increase SA Power Networks' direct accountability to its customers.

SA Power Networks is the owner and operator of South Australia's main electricity distribution network that connects over 890,000 customers to the national electricity grid. The reliability of its distribution services are regulated jointly by the Commission and the Australian Energy Regulator (**AER**). The broader economic regulatory framework supports and challenges SA Power Networks to:

- provide services at the lowest sustainable price for the quality and reliability valued by customers, and
- have in place sound and long-term asset management, operating and financing strategies and delivery, which support the provision of those services for customers of today and tomorrow.

The Commission reviews the reliability service standards that apply to SA Power Networks every five years, prior to the commencement of a new revenue regulation period. The Commission's reviews seek to establish reliability standards that are valued by customers. The AER then assesses the efficiency of SA Power Networks' plans for delivering these standards.

In establishing reliability levels that customers value, the Commission's primary objective is to protect the long-term interests of South Australian consumers with respect to the price, quality and reliability of the distribution services SA Power Networks provides. This requires an assessment of the inherent trade-off between price and reliability.

Higher distribution network reliability may provide extra benefits to customers, but may also raise costs and prices. In competitive markets, the price-service mix is optimised by consumers choosing the service they prefer, given the price. As monopolies, electricity distributors such as SA Power Networks are not subject to competitive forces influencing the price and quality of the distribution services they provide. Coupled with revenue regulation, service standard regulation seeks to determine efficient service levels for distribution services, given the absence of a competitive market.

Resolving the trade-off between price and reliability means identifying an acceptable level of network availability. This requires assessing the costs of delivering alternative reliability outcomes against customers' willingness to pay for that service.

The trade-off must also be assessed in the context of South Australia's 'state-wide pricing' arrangements. For small customers, state-wide pricing means the costs of distribution services are shared among all customers.

When considering an 'acceptable level' of availability, it is important to note that the South Australian energy market has changed markedly since the Commission last reviewed SA Power Networks' reliability standards in 2013-14. There have been changes in technology and in customer demand for energy services. In addition, extreme weather has focused attention on network resilience and response to outages. These changes have sharpened community focus on both reliability and price.

It is also important to recognise that the reliability experienced by customers is not driven solely by the reliability of the distribution network: it is also determined by the reliability of the transmission network and the reliability of generation.

The Commission's current reliability framework for SA Power Networks is established in the Electricity Distribution Code (Code) and has four main elements: network performance standards, customer service standards, the Guaranteed Service Level (GSL) scheme and monitoring and reporting requirements. This Review is proposing four broad enhancements to the Commission's current framework:

- maintaining reliability for regions
- refocusing GSL payments to customers with ongoing, persistent reliability issues
- introducing standards for new communication channels, and
- increasing SA Power Networks' direct accountability to its customers.

Maintaining reliability for regions

The Commission's draft decision is that, for 2020 – 2025, distribution network reliability performance standards will apply to ten region-based categories. Underpinning that draft decision are the propositions that region-based standards:

- are a strong communication tool that can help customers understand what to expect from SA Power Networks, and consequently improve SA Power Networks' direct accountability for its service

- will minimise the potential for localised decline in reliability that could occur over the longer term if SA Power Networks responded solely to the financial incentives provided through the AER's Service Target Performance Incentive Scheme (STPIS), which tend to promote investment in areas with higher customer density
- provide a basis for targeted reliability improvements in specific areas where a rationale, such as addressing poor performance, or promoting economic development, exists
- align with SA Power Networks' network planning practices, and
- would accommodate the performance of off-grid supply, if it becomes a regulated distribution service under the national regulatory regime.

The Commission's draft decision is to set network performance standards to maintain reliability at current levels, rather than setting targets to improve or reduce performance. This draft decision is supported by results of a customer survey showing that 73 percent of customers are satisfied with current reliability outcomes, as well as the results of the Commission's own economic assessments of reliability options.

Providing GSL payments for customers with ongoing, persistent reliability issues

To better target customers with ongoing, persistent reliability issues, the Commission is proposing to replace current duration of interruption GSL payments (duration payments), with new total annual duration of interruption payments (total duration payments).

The Review has identified that current duration payments only partially achieve the scheme objective of acknowledging that 'some of the worst served customers are unlikely to receive future service improvements due to the high costs of improving their supply'.

Current duration payments are provided to any customer that experiences a long one-off outage, with the payment amount escalating based on outage duration. Many payments have been provided to customers who generally receive average or good levels of reliability.

The Commission will also simplify the current frequency of interruption GSL payments, which are already well-targeted to customers with ongoing and persistent reliability issues, by introducing a flat payment for customers who have more than nine interruptions, each lasting for more than three minutes, in a financial year.

Duration payments account for 97 percent of total GSL scheme costs. Replacing duration payments with total duration payments will reduce the overall cost of the scheme, though costs will continue to be highly variable. Had these revisions applied in 2016-17, total duration and frequency payments are estimated to have cost $16.4 million (compared with $28.4 million for the current scheme). Had they applied in 2015-16, total duration and frequency payments are estimated to have cost $1.45 million (compared with $2.3 million for the current scheme).

Further changes to the GSL scheme set out in this draft decision include: removing GSL payments for late attendance at appointments, and removing GSL payments for repair of faulty streetlights.

In the current 2015 – 2020 period, $10.1 million per annum ($12 per year, per customer) is recovered for the GSL scheme through distribution tariffs. This amount is based on 2013-14 costs. Actual costs are highly variable, and average annual costs from 2005-06 to 2016-17 were $5.1 million.

These proposed amendments are consistent with the feedback from the customer survey about finding ways to reduce the overall cost pressures on electricity prices, while also recognising those customers experiencing ongoing reliability issues.

The proposed amendments to the GSL payment scheme will be supported by the reintroduction of annual average restoration time targets for each region, on the basis that they will strengthen the signal to SA Power Networks to restore power in a timely way (as an alternative to the signal provided by duration payments). Restoration targets will also increase the transparency around what customers can generally expect of SA Power Networks when an outage occurs.

Standards for new communication channels

Customers rely on many channels to communicate with and gain information from SA Power Networks. The Commission is proposing to add to its existing telephone and written responsiveness requirements to reflect the diversity of the methods of communication currently being used. This will include introducing:

- a requirement that outage information provided through Short Message Service (SMS) messages must be timely, current and accurate, and
- an overall communications quality measure to capture all commonly used communications channels, including the traditional channels of telephone and written enquiries, and newer channels including the corporate website, SMS messages, social media (currently Facebook and Twitter) and other media (print, radio and online).

Increasing SA Power Networks' direct accountability to its customers

SA Power Networks' reliability standards will continue to be of a 'best endeavours' nature. This means that SA Power Networks will continue to be responsible for demonstrating how it has exercised all reasonable skills and resources to meet its service standards.

However, to improve transparency around its assessments, SA Power Networks will be required to publish an annual Monitoring, Evaluation and Compliance Strategy (MECS) that outlines its strategy for applying its best endeavours. SA Power Networks will also be required to report directly to its customers on its reliability performance, including explaining where it has missed a performance target and following significant events. A further level of transparency will be achieved through the introduction of annual regional 'report cards', to assist customers in understanding performance in their area.

The Commission will conduct periodic assessments of the systems, processes and controls used by SA Power Networks to prepare and provide those reports, including the underlying data quality. It will also continue to issue long-term industry performance trends and statistics, and provide analysis of key events or compliance matters as necessary.

Next steps

The Commission invites written submissions on this paper by 14 September 2018. After considering the issues raised in submissions, the Review will deliver a final decision in December 2018.

Table 1: At a glance - summary of draft decisions

Section/element	Current arrangement	Proposed arrangement
2.1 Measures of network reliability	Average duration and frequency of interruptions (USAIDI and USAIFI).	Continue: no change.
2.2 Measures will apply to regions, not feeder categories	Feeder-type categories (four).	Region-based categories (ten).
2.3 Overall level of service: maintain, reduce or improve?	Performance targets based on five years' historical performance prior to start of regulatory period.	Maintain reliability at current levels. Performance data for both the five and 10-year periods analysed to assess preferred basis.
2.4 Targeted improvements for specific regions	n/a	No targeted improvements for low reliability feeders, or individual regions.
2.5 Standard of endeavour: absolute targets or a degree of flexibility?	Degree of flexibility: best endeavours.	Performance targets will continue to be of a 'best endeavours' nature. SA Power Networks must report directly to the public on how it has applied its best endeavours, with reference to a Monitoring, Evaluation Compliance Strategy.
2.6 Performance during significant events: included or excluded?	Performance on major event days excluded.	Continue: methodology revised for application to regions if required.
2.7 Other exclusions: revised to be consistent with STPIS reporting	Outages caused by transmission or generation failure, and momentary interruptions less than one minute.	Aligned with exclusions in the final STPIS (due mid-2018). Likely change in momentary interruption definition to less than three minutes.
3.1 Continuation of GSL payments for network reliability	Duration and frequency GSL payments.	Continue GSL payments for network reliability, swap duration payments for total duration payments.
3.2 Remove duration payments for one-off outages	Five levels of duration payments for one-off outages. Values range from $100 (12 to 15 hours) to $605 (48 hours +).	Discontinue, replace with total annual duration payments and restoration targets.
3.3 Total annual duration payments	n/a	Introduce payments for total annual outage duration, to apply at the end of each regulatory year. Three levels of payment: > 20 and ≤ 30 hours, $100; > 30 and ≤ 60 hours, $150; > 60 hours, $300.
3.4 Frequency payments	Three levels of frequency payments that apply at the end of each year. Values start at $100 for more than nine outages per annum.	Consolidate frequency payments: one level of payment: $100 for more than nine outages per annum.
3.5 Restoration targets reinstated	n/a	Reintroduce annual average restoration targets, as applied pre-2010.

Section/element	Current arrangement	Proposed arrangement
3.6 Late attendance at appointments	A payment of $25 when SA Power Networks is more than 15 minutes late for an appointment.	Discontinued.
3.7 Timeliness of new connections	A payment of $65 applies with the connection is not made on an agreed date, or within six business days if no date is agreed.	Continue: no change.
3.8 Repair of faulty street light(s)	Payment of $25 for each five/ten day period where repair takes longer than five/ten days (metro/non-metro).	Discontinued.
3.9 Performance standard for timely street light repair	n/a	Introduce a performance standard for timely street light repair: targets based on percentage of faults repaired within five days (metro) or ten days (elsewhere).
4.1 Telephone responsiveness standard	85% of calls responded to within 30 seconds.	Continue: definition revised.
4.2 Written responsiveness target: retain	95% of enquiries responded to in five business days.	Continue: no change.
4.3 SMS communication standard introduced	n/a	Require that when providing information about outages by SMS, SA Power Networks must ensure that information is timely, current and accurate.
4.4 Communication quality measure: for monitoring	n/a	Require SA Power Networks to report on a communication quality measure, as agreed with the Commission, initially for reporting only.
5.1 SA Power Networks will report directly to its customers	Commission publishes a series of reports on SA Power Networks' performance.	SA Power Networks publishes its own performance reports, with oversight and scrutiny by the Commission.
5.2 Annual regional report cards	n/a	Reporting includes a set of annual regional report cards.
5.3 Reporting on low reliability feeders	Low reliability feeders have USAIDI twice as high as the target for that feeder class for two consecutive financial years.	Low reliability feeders have USAIDI twice as high as the target for that region for two consecutive financial years.
5.4 Electricity Guideline No. 1 will be revised	Electricity Guideline No. 1 outlines data required by the Commission.	Electricity Guideline No. 1 will be revised to reflect the Commission's final decision on reliability standards for 2020 – 2025.
5.5 SA Power Networks must publish time-series data	The Commission publishes time-series data on its website.	SA Power Networks will be required to provide and publish time-series data (from 2005-06 onwards) that is consistent with the overall revised framework.

1 Introduction

The Essential Services Commission (**Commission**), established under the Essential Services Commission Act 2002 (**ESC Act**), is the independent economic regulator of essential services in South Australia. In undertaking its regulatory functions, the Commission's primary objective is the protection of the long-term interests of South Australian consumers with respect to the price, quality and reliability of essential services.[1]

SA Power Networks is the owner and operator of South Australia's main electricity distribution network that connects over 890,000 customers to the national electricity grid.[2] SA Power Networks' distribution network links the transmission network, which supplies electricity from larger generators, with customers. It also supports growing amounts of small-scale generation connected directly to the distribution network.

The Commission and the Australian Energy Regulator (**AER**) jointly undertake economic regulation of the electricity distribution services provided by SA Power Networks. The Commission's role is to set and review the reliability standards that apply to SA Power Networks.

The AER's role includes making five-yearly revenue determinations for SA Power Networks, and administering the Service Target Performance Incentive Scheme (**STPIS**), which provides incentives for SA Power Networks to maintain and improve average performance (see Box 1). [3]

The Commission's power to set and review SA Power Networks' reliability standards is established by the Electricity Act 1996 (**Electricity Act**), and is supported by the provisions of the Australian Energy Market Agreement, National Electricity Law, National Electricity Rules, National Energy Retail Law and National Energy Retail Rules.[4]

Under the Electricity Act, SA Power Networks is required to hold a licence authorising it to operate the electricity distribution system in South Australia. The Commission is the licensing authority for the purposes of the Electricity Act. The Electricity Act mandates certain licence terms and conditions, while providing the Commission with the discretionary power to include additional licence terms and conditions.

The Electricity Distribution Code version 12.1 (**Code**) establishes the reliability standard framework that applies to SA Power Networks, and compliance with the Code forms a condition of SA Power Networks' distribution licence. The reliability standard framework has four main elements: network performance standards and targets, a Guaranteed Service Level (**GSL**) scheme, customer service standards, and monitoring and reporting requirements.

The current five-year revenue determination period ends on 30 June 2020. The Commission is conducting a review of the reliability standard framework that applies to SA Power Networks, ahead of the 1 July 2020 – 30 June 2025 regulatory period (**Review**). This draft decision is presented for consultation. The Review will deliver a final decision in December 2018.

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1 ESC Act, section 6(a)

2 890,000 represents the number of meters (National Meter Identifiers) active in the last year. A smaller number of meters – approximately 860,000 – are active at any one point in time.

3 The AER assesses SA Power Networks' revenue proposal with reference to national and state requirements, including the reliability standards established by the Commission. The National Electricity Rules stipulate that a distributor's revenue allowance be set to deliver against service standards for maintaining network reliability. On this matter, section 6.5.6 of the National Electricity Rules relates to forecast operating expenditure, and section 6.5.7 relates to capital expenditure.

4 The Australian Energy Market Agreement provides for State and Territory Governments to retain responsibility for developing service reliability standards to ensure network security and reliability. The Commission is responsible for developing, implementing and administering the jurisdictional service standards for SA Power Networks.

Box 1: The Service Target Performance Incentive Scheme

The STPIS is the main financial incentive mechanism in the broader service standard framework for SA Power Networks. It has applied since 2010 when it replaced the Commission's Service Incentive Scheme.

The purpose of the STPIS is to provide incentives for distributors to improve and maintain reliability performance where improvements are valued by customers. It is administered by the AER in accordance with National Electricity Rule requirements.[5]

The STPIS aims to ensure that service levels do not fall as distributors strive to achieve efficiency gains, typically associated with a reduction in expenditure. It balances other AER mechanisms that incentivise reduced expenditure, but do not take into account network performance.

The STPIS has four components: reliability of supply, quality of supply, customer service and a GSL scheme. The AER decides how the STPIS will apply to each distributor as part of the revenue determination process.

As it currently applies to SA Power Networks, the STPIS relates to reliability of supply (duration and frequency of interruptions, for each feeder type) and customer service (telephone answering). [6] Targets are set as an average of five years' performance. As a jurisdictional GSL scheme is in place, the STPIS GSL scheme does not apply.[7]

An incentive of up to five percent of SA Power Networks' total revenue allowance applies to performance against these parameters. The incentive rewards SA Power Networks for improving and maintaining performance, and penalises SA Power Networks for declining performance (also by up to five percent).

The STPIS is currently under review. In December 2017 the AER published a draft amended STPIS.[8] A final revised STPIS is expected in mid-2018, but had not been published at the time of this draft decision.

1.1 Changes since the last review

The South Australian energy market has changed markedly since the Commission last reviewed SA Power Networks' reliability standards in 2013-14. There have been changes in technology and in customer demand for and expectations of energy services. In addition, extreme weather has focused attention on network resilience and response to outages. These changes have sharpened community focus on both reliability and price.

1.2 Review objective

This Review is seeking to define reliability levels that are valued by customers. This task will support the broader economic regulation of SA Power Networks, which the Commission jointly administers with the AER. The broader economic regulatory framework supports and challenges SA Power Networks to:

- provide services at the lowest sustainable price for the quality and reliability levels valued by customers, and

5 National Electricity Rules, clause 6.6.2

6 AER, October 2015, SA Power Networks – Determination 2015 – 2020, Attachment 11, pp. 10-11, see https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/final-decision

7 STPIS section 6.1 (a)

8 AER 2017, Draft Amended Service Target Performance Incentive Scheme, see https://www.aer.gov.au/system/files/AER%20-%20Draft%20amended%20service%20target%20performance%20incentive%20scheme%20-%20December%202017.pdf

- have in place sound and long-term asset management and financing strategies and delivery, which support the provision of those services for customers of today and tomorrow.

In defining reliability standards that customers value, the Review's primary objective is that of section 6 of the ESC Act: the protection of the long-term interests of South Australian consumers with respect to the price, quality and reliability of essential services.[9]

In pursuing this primary objective, the ESC Act requires the Commission to have regard to the need to:

i. promote competitive and fair market conduct; and

ii. prevent misuse of monopoly or market power; and

iii. facilitate entry into relevant markets; and

iv. promote economic efficiency; and

v. ensure consumers benefit from competition and efficiency; and

vi. facilitate maintenance of the financial viability of regulated industries and the incentive for long-term investment; and

vii. promote consistency in regulation with other jurisdictions.

1.2.1 Developing reliability standards that customers value

Developing reliability standards that customers value requires assessing the inherent trade-off between price and reliability. Higher reliability levels may provide extra benefits to customers, but also raise costs and prices.

In competitive markets, the price-service mix is optimised by consumers choosing the service they prefer, given the price. As monopolies, electricity distributors such as SA Power Networks are not subject to competitive forces in relation to the price and quality of the distribution services they provide. Coupled with revenue regulation, service standard regulation seeks to determine efficient service levels for distribution services, given the absence of a competitive market.

With respect to the trade-off between price and reliability, it is useful to emphasise that the reliability experienced by customers is not driven solely by the reliability of the distribution network. It is also determined by the reliability of the transmission network, and reliability of generation. Nor are distribution costs the sole component of electricity prices, or electricity price increases.[10]

The distribution network transports electricity from exit points on the transmission network to customers, and connects distributed generators to customers. SA Power Networks' contribution to reliability is to have the network in operating order so this can occur.

Resolving the trade-off between price and reliability means identifying an acceptable level of network availability. This requires assessing the costs of delivering alternative reliability outcomes against customers' willingness to pay for that service.

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[9] In the December 2017 Objectives and Process paper, the Review objective was defined as 'to establish reliability standards that require SA Power Networks to provide distribution services valued by customers at an acceptable cost'. In its submission to the December 2017 Objectives and Process paper, the South Australian Council for Social Services (SACOSS) argued that that it is not necessary to have an objective for the Review that is separate from the objective of the ESC Act. The Commission accepts this comment, and has reframed the original objective.

[10] In relation to reliability, in 2016-17, half of all time off supply was due to transmission and generation outages. In relation to price, distribution costs account for 26.2 per cent of a typical residential customer's annual electricity bill. Other components are generation and retail (50.3%), GST (9.1%), transmission (7%), green and energy efficiency scheme costs (3.4%), PV feed-in-tariffs (2.6%) and metering (1.4%).

The trade-off must be assessed in the context of South Australia's 'state-wide pricing' arrangements. For small customers, government provision for state-wide pricing means the costs of distribution services are shared amongst all customers.[11] This tempers the fact that the cost of providing distribution services is highly dependent on location.[12]

1.3 Review process

This Review began in 2017, at the same time as SA Power Networks began customer engagement to inform its revenue proposal for the 2020 – 2025 period.[13] The Review has drawn on a broad evidence base to reach this draft decision. The evidence base has included:

- SA Power Networks' customer engagement program[14]
- direct consultation with stakeholders
- submissions in response to an Objectives and Process paper published in December 2017[15]
- issues identified through performance monitoring and reporting
- workshops with SA Power Networks[16]
- discussions with other regulators
- relevant national benchmarking
- complaints data from the Energy and Water Ombudsman of South Australia, and
- economic assessment of reliability standard options.

Each of these elements is an input to the Review; the Commission has not relied on any one single input in making this draft decision. The Commission has considered evidence from each source, and weighed it in the context of its statutory requirements.

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[11] State-wide pricing applies for customers with annual consumption less than 160 MWh. Section 35B of the Electricity Act provides for the Treasurer to make an Electricity Pricing Order. State-wide pricing provisions were established in the Electricity Pricing Order implemented on 11 October 1999, as summarised in the South Australian Government Gazette, p. 1471.

[12] In general, costs are higher to provide services to customers in areas with low customer density. If network charges reflected locational costs, charges would double for many rural customers – see SA Power Networks 2016, Pricing Proposal 2016-17, p. 25.

[13] The National Electricity Rules require SA Power Networks to engage with its customers directly and demonstrate how customer concerns have been taken into account in developing its revenue proposal for the AER. SA Power Networks conducted its customer engagement program to understand the expectations, views and priorities of its customers to inform its 2020-2025 revenue proposal. The scope of the program extends beyond network reliability. The Commission has observed and had oversight of the program.

[14] Details of the engagement, including several reports, are available at www.talkingpower.com.au Early in the Review, the Commission provided SA Power Networks with a set of customer engagement principles. These complemented SA Power Networks' existing customer engagement principles (SA Power Networks, Stakeholder Engagement Strategy 2016, https://www.sapowernetworks.com.au/public/download.jsp?id=65108) and the AER customer engagement guidelines (AER, Consumer engagement guideline for network service providers 2013, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/consumer-engagement-guideline-for-network-service-providers).

[15] Submissions were received from SA Power Networks, SACOSS, the Energy and Water Ombudsman of South Australia, Business SA, the Clean Energy Council, AGL and S&C Electric, and are available at https://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/sa-power-networks-2020-reliability-standards-review

[16] The Commission held a series of workshops with SA Power Networks in October 2017, with the objective of developing options for revised reliability standards that respond to the themes raised in customer engagement, issues identified through performance monitoring and reporting, and the Commission's direct consultation with stakeholders. Members of SA Power Networks' regulatory, reliability, customer service, and customer engagement teams attended the workshops. Senior managers in the Commission and SA Power Networks attended both an initial session to agree on the scope of the workshops and a final session to discuss the results of those workshops.

1.4 SA Power Networks' performance

The underlying reliability of the distribution network from 2005-06 to 2016-17 has been reasonably consistent, albeit that some elements were adversely affected in 2016-17 by severe weather (Eastern Hills and Eyre Peninsula) and equipment failure (Central Business District (CBD) feeders).

On a feeder-type category basis, performance from 2005-06 to 2016-17 has been reasonably consistent for urban feeders and has steadily improved for CBD, urban, rural short and rural long feeders. However, CBD feeders and rural short feeders did not meet performance targets in 2016-17.

On a reporting region basis, performance from 2005-06 to 2016-17 has been reasonably consistent across regions within the State. Performance declined in the Eastern Hills and Fleurieu Peninsula and Upper North and Eyre Peninsula in 2016-17 due to the impact of severe weather, and in the Adelaide Business Area (CBD) in 2016-17 due to equipment failure.

The Commission currently reports on performance annually and quarterly. Further detail on performance for the whole distribution system, each feeder-type category and reporting region is available in the annual regulatory performance reports and quarterly operational performance and monitoring reports (see www.escosa.sa.gov.au).

1.4.1 Looking 'behind the averages'

The trends discussed above are for average (mean) performance, which is the basis of the Commission's network performance targets. Averages do not reflect the experience of individual customers: some customers experience performance that is better than average and some experience reliability that is below average (see Box 2).

Variation in performance around the mean is normal in electricity distribution networks, and reflects the random nature of unplanned interruptions, and that the network has pockets of low customer density, where cost of reliability for each customer is high because of limited economies of scale.

Historically, the Commission's reliability standards have been concerned with the experience of customers not well served by broad targets for average performance. This is evidenced in continued reporting on low reliability feeders[17], setting performance standards for individual regions prior to 2015, and by including performance for worst served customers as the main parameter in the Service Incentive Scheme (administered by the Commission prior to introduction of the STPIS).

Box 2: How do individual customers experience reliability?

To investigate how the experience of customers varies from the mean, average annual duration of interruptions of 1631 of SA Power Networks distribution feeders, for the 2010-11 to 2016-17 period has been analysed.[18] Results illustrate how the experience of individual customers varies.

This data is normalised. The impact of outages caused by loss of transmission or generation supply, and significant events, currently defined as major event days (MEDs), is excluded.

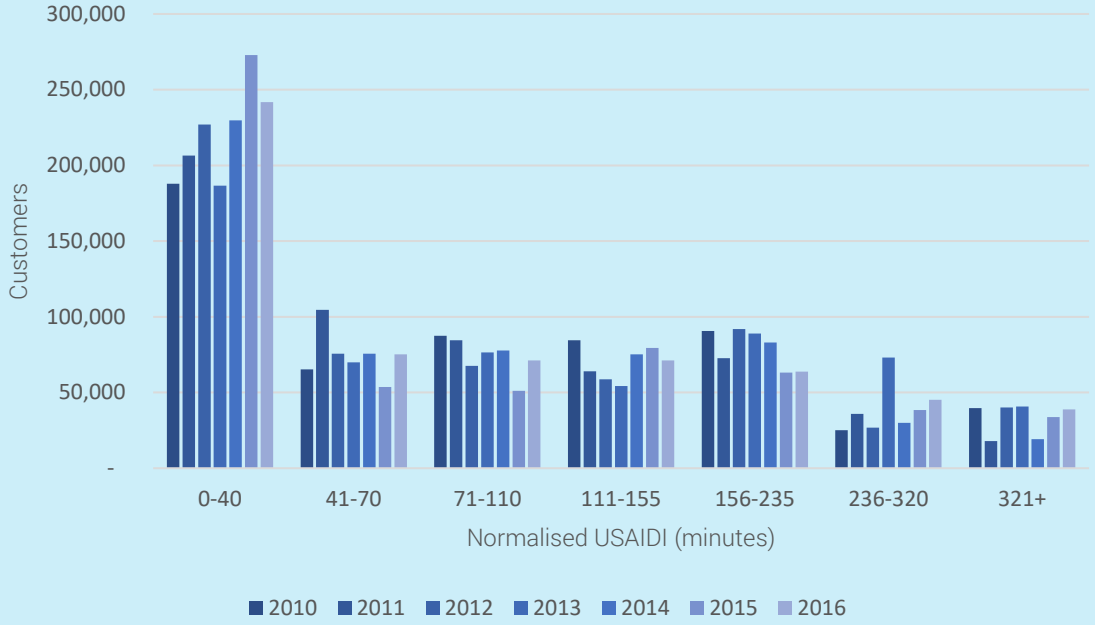
Urban feeders

Average (mean) annual duration of interruptions for customers on urban feeders is 110 minutes (2016-17). However, half of all urban feeders have interruptions of 40 minutes or less, and five percent of urban feeders have interruptions of 321 minutes or more. This, with change over time, is illustrated below.

[17] Low reliability feeders have USAIDI twice as high as the target for that feeder class for two consecutive financial years.

[18] SA Power Networks has 1726 distribution feeders. Feeders that straddle the border of the CBD and Adelaide Metropolitan Area were excluded from this analysis.

Figure 1: Average annual duration of interruptions (minutes) 2010-11 to 2016-17[19]



Short rural feeders

Similarly, average annual duration of interruptions for customers on short rural feeders is 230 minutes (2016-17). However, half of all short rural feeders have interruptions of 120 minutes or less, and five percent of short rural feeders have interruptions of 900 minutes or more.

Long rural feeders

Average annual duration of interruptions for customers on long rural feeders is 265 minutes (2016-17). However, half of all long rural feeders have interruptions of 180 minutes or less, and five percent of long rural feeders have interruptions of 1365 minutes or more.

1.4.2 Performance compared with relevant national benchmarking

The Commission is required by the Electricity Act to have regard to relevant national benchmarks in establishing reliability standards. The AER publishes an annual benchmarking report that covers all Australian electricity distributors.[20]

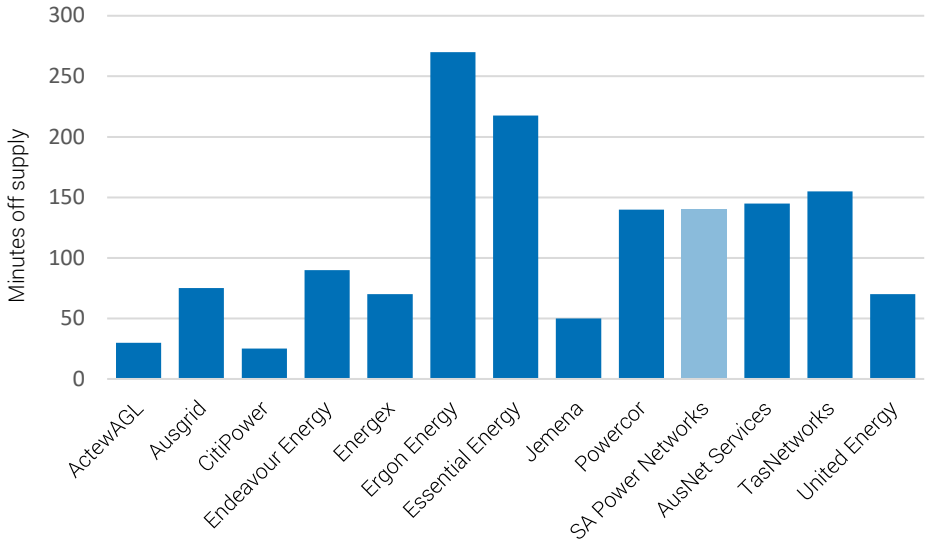
It includes benchmarking of electricity supply reliability, using average number of minutes off supply per customer per annum, and the average number of interruptions per customer per annum, as shown in Figure 2 and Figure 3.[21]

[19] Here, the first category represents performance up to the 50th percentile, with the following categories representing the 60th, 70th, 80th, 90th and 95th percentiles, and the final category representing performance beyond the 95th percentile. When data is prepared with additional categories below the 50th percentile, the distribution remains skewed to the right. The reliability experience of the customers above the 50th percentile varies much more than that of customers below the 50th percentile.

[20] AER, November 2017, Distribution Network Service Provider Annual Benchmarking Report, https://www.aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf

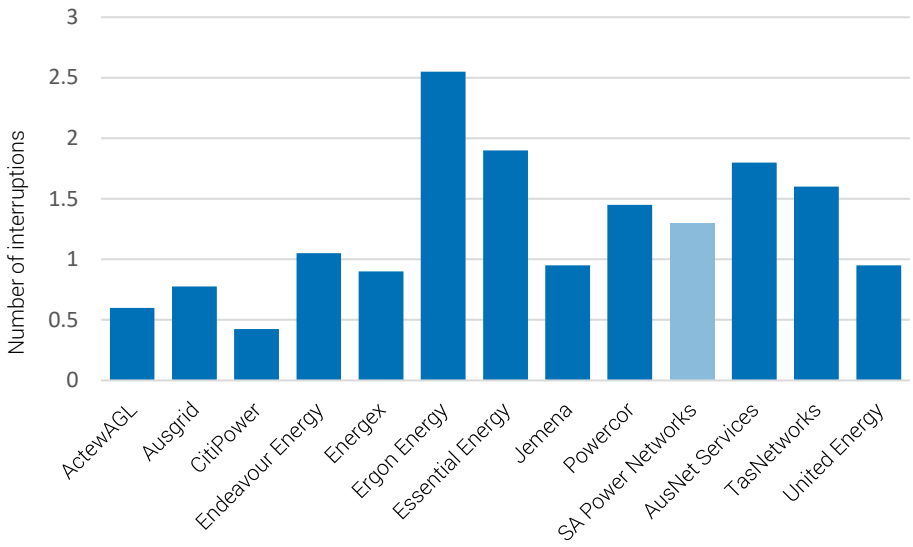
[21] Data excludes the effects of major events, planned outages and transmission outages, and is comparable with the Commission's data on SA Power Networks' performance.

Figure 2: Average minutes off supply per customer across Australian electricity distributors (2012 – 2016)



Source: Australian Energy Regulator, 2017, Distribution Network Service Provider Annual Benchmarking Report, p. 62.

Figure 3: Average number of interruptions per customer across Australian electricity distributors (2012 – 2016)



Source: Australian Energy Regulator, 2017, Distribution Network Service Provider Annual Benchmarking Report, p. 62.

These reliability performance measures are strongly related to customer density (number of customers per kilometre of line), which varies across distributors.

In recent analysis, the Australian Energy Market Commission (AEMC) used distributor data to demonstrate that grid supply in low-density areas can be less reliable (and more costly) than in high-

density areas. The AEMC notes that even greater extremes would be expected if data were available at higher resolution (ie within each distributor's network). [22]

SA Power Networks has customer density of around ten customers per kilometre of line. The most comparable distributors are Powercor (Western Victoria, 12 customers/km), TasNetworks (14 customers/km), and AusNet Services (Eastern Victoria, 18 customers/km).[23] SA Power Networks performs well in comparison to these distributors.

1.5 Outline of this draft decision

The remainder of this draft decision is organised around each of the reliability standard framework's four main elements: network performance standards and performance targets (section 2), the GSL scheme (section 3), customer service standards and targets (section 4) and reporting and monitoring (section 5). Each of these sections outlines the Commission's draft decisions, existing arrangements, and rationale for any proposed changes to apply from 1 July 2020.

[22] AEMC, 2017, National Electricity Amendment (Alternatives to grid-supplied network services) Rule 2017 pp. 15-18, https://www.aemc.gov.au/Rule-Changes/Alternatives-to-grid-supplied-network-services

[23] AER, 2017, Distribution Network Service Provider Annual Benchmarking Report, p. 66, https://www.aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf

2 Average annual network performance standards

This section addresses the first of the reliability standard framework's four main elements: average annual network performance standards.

The Code currently sets average annual network performance standards for each of four feeder-type categories: CBD, urban, short rural and long rural. Performance standards are in two parts.

First, performance targets are established based on historical performance. Performance targets are set for average duration and frequency of interruptions. Targets relate to normalised performance, where outages caused by loss of transmission or generation supply and the impact of Major Event Days (MEDs) are excluded from performance data.

Second, if a performance target is not met, the Commission will assess if SA Power Networks has used its 'best endeavours' to achieve the target, defined as 'to act in good faith and use all reasonable efforts, skills and resources'. If SA Power Networks is assessed as using its best endeavours, the reliability standard is met.

2.1 Measures of network reliability

The draft decision is to continue to use measures of average duration and frequency of interruptions (measured as USAIDI and USAIFI) to set average annual network performance standards.

Unplanned System Average Interruption Duration Index (USAIDI) expresses duration of unplanned interruptions as the average duration of interruption, in minutes, across all customers in a category, over a year.

Unplanned System Average Interruption Frequency Index (USAIFI) expresses frequency of unplanned interruptions as the average number of interruptions across all customers in a category, over a year.

2.1.1 Rationale

The draft decision is to continue the existing arrangement, for three reasons. First, output measures (like USAIDI and USAIFI) prescribe an outcome for customers and allow distributors (here, SA Power Networks) flexibility around how to direct investment to achieve that outcome. This means that the particular technical solution is not prescribed – it is for the business operator to determine, provided it meets the intended outcome at least cost — and so promotes efficiency and enhances innovation.

Second, output measures are used commonly in Australia and overseas, are recommended in the AER draft Distribution Reliability Measures Guideline and are the basis of the STPIS.[24, 25] Third, the Commission has used these measures historically. Continuing to do so ensures consistency and allows time series comparison.

[24] The AER is consulting on this draft distribution reliability measures guideline, which prescribes a set of common definitions and measures to assess and compare the reliability performance of distributors. A final guideline is due in mid-2018. See: AER, 2017, Draft Distribution Measures Guideline, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/draft-distribution-reliability-measures-guideline-2017

[25] Alternative 'input' standards relate to the inputs to network planning required to deliver reliability performance. Examples include prescribing the availability of bulk supply (as with the national electricity market bulk supply standard of prescribing maximum unserved energy), or defining categories to drive particular levels of redundancy in the network (as in the Commission's Electricity Transmission Code).

There are a number of reliability output measures. For example, the AER draft Distribution Reliability Measures Guideline lists both planned and unplanned:

- SAIDI, System Average Interruption Duration Index
- SAIFI, System Average Interruption Frequency Index
- CAIDI, Customer Average Interruption Duration Index
- MAIFIe, Momentary Average Interruption Duration Index, and
- Supply reliability levels experienced by the worst served customer.

The Commission has previously decided not to use CAIDI, which represents average interruption length for all customers who have interruptions. [26, 27] CAIDI closely reflects the experience of a power interruption for an individual customer. However, it does not represent the number of customers whose power stays on, and so does not reflect efforts by distributors to prevent interruptions occurring. In contrast, SAIDI and SAIFI translate the impact of interruptions to the whole customer group, and so reflect efforts to prevent interruptions.

The draft decision is not to establish standards for momentary interruptions.[28] Technologies such as reclosers and feeder automation allow some long outages to be resolved quickly – essentially turning them into momentary interruptions. The reliability standards framework seeks to encourage this, by not establishing targets to limit the number of momentary interruptions.

2.2 Measures will apply to regions, not feeder categories

The draft decision is to set network performance standards for ten region-based categories rather than four feeder-type categories.

SA Power Networks' distribution system comprises some 1,720 feeders. It is not feasible to set and monitor service standards for each individual feeder, so the Commission must consider how to segment the network to monitor system performance.

Reliability varies across the distribution network, feeder by feeder, depending on the physical structure of the network and the number of redundant elements it contains.[29] Two generally utilised network segmentation methodologies are: geographic regions, which represent differences in reliability performance across the state; and, feeder categories based on feeder line length, customer load and level of redundancy.

Feeder-type categories have been the basis for network performance standards since 2015, when the Commission replaced the previous region-based categories. Prior to 2015, network performance standards applied to seven regions, which still form the basis for reporting by the Commission.

The proposed ten region-based categories are nine distinct geographic regions, and a tenth category for major regional centres (MRCs). The proposed categories are set out in Table 2, which also compares each with the seven regions the Commission currently uses for reporting, and SA Power Networks' network planning regions.

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[26] Essential Services Commission of South Australia, April 2005, 2005 – 2010 Electricity Distribution Price Determination Part A: Statement of Reasons

[27] For example, if one customer had an outage of 60 minutes CAIDI would be 60 minutes. Likewise, if 100,000 customers had an outage of 60 minutes, CAIDI would be 60 minutes.

[28] Momentary interruptions are currently defined as interruptions lasting less than one minute. This draft decision proposes changing that definition to be interruptions lasting less than three minutes (see section 2.7.1).

[29] Redundant elements mean that if one element fails, supply is not interrupted because electricity can be delivered through another path.

Table 2: Proposed region-based categories

Proposed region-based category	Definition, with respect to current Commission reporting regions	Aligned SA Power Networks' planning regions
Adelaide Business Area (ABA)	ABA boundary revised to reflect development in the CBD since 1999, as shown in Figure 4.	Adelaide Central Region
Adelaide Metropolitan Area (AMA)	Major Metropolitan Area (Adelaide feeders only), plus agreed feeders in Gawler.	Metro East, Metro West, Metro North and Metro South
Major Regional Centres (MRC)	Agreed feeders in Urban Centres and Localities with a population of 10,000 or more at the 2016 census, except Adelaide and Gawler.[30] Currently, select feeders in Mount Barker, Port Augusta, Port Lincoln and Whyalla are included in the Major Metropolitan Area Code reporting region.	Included in individual planning regions
Barossa, Mid-North and Yorke Peninsula	As per existing 'Barossa, Mid North, Riverland and Murraylands' reporting region, with the Riverland and Murraylands excluded to become a separate region, and with agreed feeders in Gawler excluded and incorporated in the AMA.	Barossa, Mid-North, Yorke Peninsula
Eastern Hills	As per existing 'Eastern Hills and Fleurieu' reporting region, with Fleurieu excluded to become a separate region.	Eastern Hills
Eyre Peninsula	As per existing 'Upper North and Eyre Peninsula' reporting region, with the Upper North excluded to become a separate region.	Eyre
Fleurieu Peninsula	As per existing 'Eastern Hills and Fleurieu' reporting region, with Eastern Hills excluded to become a separate region, and the addition of Kangaroo Island.[31]	Fleurieu Peninsula

30 These are Crafers-Bridgewater, Mount Barker, Mount Gambier, Murray Bridge, Port Augusta, Port Lincoln, Port Pirie, Victor Harbor, and Whyalla. Urban Centres and Localities are defined by the Australian Bureau of Statistics: see http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/05773C1D8C9F2022CA257A98001399F7?opendocument

31 Kangaroo Island is included in the new Fleurieu Peninsula region. This is justified by improvements in reliability performance on Kangaroo Island over the last decade. For the 2010 – 2015 regulatory period, a specific target was set for Kangaroo Island as a special case. Historical reliability performance of the Kangaroo Island distribution network indicated that there was a problem associated with reliability of electricity supply to the Island. Average duration of outages were typically three to five times greater than on other parts of the rural network in South Australia. The characteristics of the Kangaroo Island network, and the environment in which it is located, also contributed to this problem. As a result, a specific target was set for the Island, on the basis that its particular characteristics and the historical performance experienced by customers justified special treatment. The target was achieved.

Proposed region-based category	Definition, with respect to current Commission reporting regions	Aligned SA Power Networks' planning regions
Riverland and Murraylands	As per existing 'Barossa, Mid North, Riverland and Murraylands' reporting region, with the Barossa and Mid North excluded to become a separate region.	Riverland and Murraylands
South East	No change	South East
Upper North	As per existing 'Upper North and Eyre Peninsula' reporting region, with the Eyre Peninsula excluded to become a separate region.	Upper North

2.2.1.1 Revisions to the Adelaide Business Area

The draft decision is to revise the Adelaide Business Area (ABA) boundary, as indicated in Figure 4, to reflect development in the CBD since the Code came into effect in 1999. The current ABA is illustrated in Schedule 1 of the Code.

Since 1999, there has been substantial commercial, high-rise development to the south and west of the current boundary, and development on the north-west corner including the new Royal Adelaide Hospital and medical research facility.

The boundary in Figure 4 is based on the land use zones defined by Adelaide City Council.[32] It captures Adelaide City Council's Capital City Zone, Riverbank Zone, and Institutional Zones above North Terrace. The boundary in Figure 4 shows a straight edge, whereas the actual Capital City Zone is aligned with individual land parcel boundaries.

A key matter in defining the ABA is practicality in measuring performance: SA Power Networks must be able to readily identify the feeders, or parts of feeders, that serve the ABA. In order to achieve this, it may be necessary to realign the southern edge of the proposed area (for example, east-west along Carrington Street).

2.2.1.2 Major regional centres

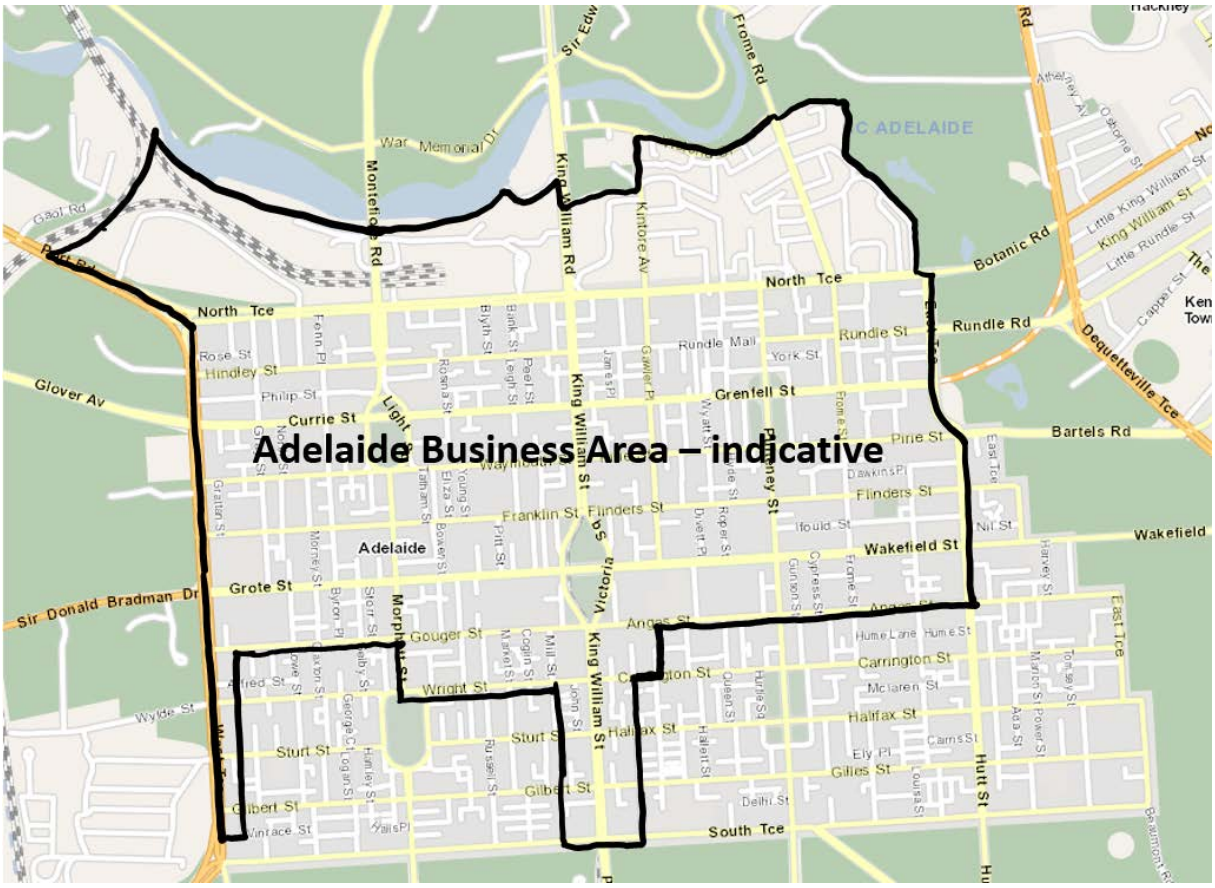
This category has been introduced because MRCs are unique. On average, they have significantly better reliability than both the non-urban parts of regional areas, and metropolitan Adelaide.

For example, the average USAIDI from 2012 – 2017 for the Eyre Peninsula excluding Port Lincoln and Whyalla (MRCs) was 450 minutes. With Port Lincoln and Whyalla included, average USAIDI was 235 minutes.

Performance tends to be better in MRCs because response times are shorter (with depots often located in these centres), and because of the smaller, relatively simple nature of the networks.

[32] Adelaide City Council, 2017, Adelaide (City) Development Plan Zone Map Gazetted 30 May 2017, https://www.cityofadelaide.com.au/assets/documents/MAP-development-plan-zone.pdf

Figure 4: Proposed revision to boundary of the Adelaide Business Area



2.2.2 Existing arrangement

Currently, network performance standards apply to each of four feeder-type categories: CBD, urban, short rural and long rural. The definition of each feeder-type category is set out in Table 3.

Table 3: Feeder-type categories as defined in the current Electricity Distribution Code

Feeder-type category	Definition
CBD feeder	A feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas
Urban feeder	A feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 mega-volt amps/km.
Short rural feeder	A feeder, which is not a CBD or urban feeder, with a total feeder route length less than 200 km. Short Rural feeders may include feeders in urban areas with low load densities.
Long rural feeder	A feeder, which is not a CBD or urban feeder, with a total feeder route length greater than 200 km.

2.2.3 Rationale

There are six reasons for proposing performance standards based on the regions outlined in section 2.2:

- They are a better tool for communication than feeder-type categories.

One function of minimum performance standards is that they help people understand what SA Power Networks must deliver. Region-based standards are accessible and understandable to customers, can inform customer expectations about performance, and so improve the potential for SA Power Networks to be accountable for the service it provides.

- They minimise the potential for localised decline in reliability.

The STPIS does not include a strong mechanism to prevent reliability decline in regions. Instead, it incentivises SA Power Networks to make and maintain improvements to average reliability for each feeder-type category.

Investing in areas with higher customer density produces the greatest impact on average reliability, and this tends to be at a lower cost (given higher customer densities and the associated economies of scale and scope available).

It is reasonable to expect that, over time, reliability improvements in higher density areas might offset decline in lower density areas. This would only be evidenced in the medium to long term but once it eventuates, rectification is likely to be more complex and costly. While no such decline has been observed since switching to feeder-type categories in 2015, setting standards for regions seeks to prevent this issue before it occurs.

- They provide the basis for targeted improvements in specific areas where a broader driver or rationale, such as addressing poor performance or promoting economic development, exists.

Some customers and localities are not served well by the current feeder-type broad targets for average performance. However, region-based standards can be used to drive reliability step changes. For example, a specific target was set for Kangaroo Island as a special case in the Commission's review for the 2010-2015 regulatory period (as discussed in the note to Table 2). Further, targeted improvements for regions have the potential to align with regional economic development imperatives, or broader urban and regional planning objectives.

- They align with SA Power Networks' network planning practices.

To achieve reliability outcomes, SA Power Networks conducts network planning for each of its network planning regions.

This involves developing a set of input-based network planning criteria (ie required levels of redundancy), and applying procedural, response, design, technical, and safety standards (as brought together in annual Safety, Reliability and Maintenance Technical Management Plans (SRMTMPs), approved by the Technical Regulator). Operationally, SA Power Networks monitors performance of individual feeders and, if necessary, makes changes to achieve reliability outcomes.

- They would accommodate the performance of off-grid supply, if it becomes a regulated distribution service.

The AEMC recently decided favourably on the principle of allowing off-grid supply as an alternative to grid-supplied network services. [33] If off-grid supply becomes a regulated distribution service and

[33] AEMC 2017, National Electricity Amendment (Alternatives to grid-supplied network services) Rule 2017, https://www.aemc.gov.au/Rule-Changes/Alternatives-to-grid-supplied-network-services

is provided by SA Power Networks, its reliability performance would have to comply with the Code. Off-grid supply would be difficult to relate to the Code's current feeder-type category targets; however, it would relate simply to the region-based based targets.

- In other jurisdictions where feeder-type categories are used to set reliability standards, there is more than one distributor. This means that the schemes are, in practical effect, similar to a region-based approach.

Many of these reasons reflect the Commission's findings in its 2017 Eyre Peninsula Inquiry, which found that feeder-type targets did not provide strong and clear incentives for SA Power Networks to maintain regional performance.[34]

They also align with the increased customer focus on reliability in regions since the Commission's last review of reliability standards. During SA Power Networks' customer engagement process, some participants expressed concern about the ongoing difference in service levels between metropolitan and regional customers. This draft decision seeks to provide a pragmatic, targeted and cost-effective approach to addressing these factors.

2.2.3.1 Region-based standards and the STPIS

When the Commission introduced feeder-type categories as the basis for network performance in 2015, the rationale was that it would improve national consistency, align with the STPIS, and allow benchmarking against other jurisdictions.

The Commission has changed its view on the importance of jurisdictional reliability standards and the STPIS using the same network segments. Its view now is that there is no contradiction between region-based jurisdictional standards and feeder-type based STPIS incentives. They have different purposes.

Jurisdictional reliability standards provide a reference point for minimum service. Revenue allowances must provide for delivering against those minimum standards, that is, to **maintain** services.[35] The STPIS provides for services to be continually improved.

The National Electricity Rules separately require that the AER provide incentives (currently the STPIS) for distributors to **maintain and improve** services.[36] To give proper effect to the national scheme of regulation, it is important that the two sets of provisions operate independently.

2.3 Overall level of service: maintain, reduce or improve?

The draft decision is to set network performance targets to maintain reliability at current levels.

Reliability at current levels will be defined as performance over either five or ten years. Performance over each period will be assessed ahead of 1 July 2020. Where there are material differences, in defining 'current levels' the Commission will have regard to:

- maintaining reliability outcomes, and
- mitigating the impact of recent poor performance, if applicable.[37]

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[34] Essential Services Commission of South Australia, Inquiry into reliability and quality of electricity supply on the Eyre Peninsula Final Report October 2017, https://www.escosa.sa.gov.au/projects-and-publications/projects/inquiries/inquiry-into-reliability-and-quality-of-electricity-supply-on-the-eyre-peninsula

[35] National Electricity Rules, clause 6.5.7(a)

[36] National Electricity Rules, clause 6.6.2(a)

[37] This may be the case for the Adelaide Business Area. SA Power Networks did not met the performance target for CBD feeders (equivalent to the Adelaide Business Area) in either 2016-17 or 2017-18. In its submission to this Review's Objectives and Process paper, SA Power Networks argued that future targets for this area should reflect its 'inherent stability', which is reflected in 'historic performance over a period longer than five years'.

For the 2015 – 2020 period, network performance targets were set based on the average of five years' performance prior to the start of the regulatory period.

2.3.1 Rationale

The draft decision to set network performance targets to maintain reliability at current levels of performance is justified for three reasons:

- A reduction on long-term average performance would not meet requirements of the Electricity Act, and would yield limited cost savings.
- Customers have expressed overall satisfaction with current levels of reliability.
- There is no clear economic benefit in setting targets to improve reliability performance.

These reasons are each detailed further below.

2.3.1.1 Performance targets cannot be set to reduce reliability performance

In SA Power Networks' customer engagement process, some people expressed a preference to accept reliability reductions in order to reduce costs.[38] Further, the South Australian Council of Social Services (SACOSS) submission to the Commission's Objectives and Process paper asked for reduced reliability to be included in any economic assessment, on the basis it may deliver cost savings.

Ultimately, scenarios for reducing reliability performance targets were not assessed, as a reduction would not meet requirements of the Electricity Act. Section 23 (1)(n)(v) of that Act requires standards to be set to maintain reliability relative to 1998-99 levels. Reliability has not definitively improved since then, so the Commission may not set long-term network performance standards to reduce reliability. This is discussed further in Appendix 1.

Although legal requirements prevent setting network performance standards to 'reduce' reliability, the Review nevertheless considered whether doing so would deliver cost savings. It found that, in the current environment of electricity consumption and demand in South Australia, marginal expenditure on network reliability is low and hence reduced standards would not deliver meaningful cost reduction for consumers.

In SA Power Networks' current revenue determination, $25 million over five years is identified for maintaining jurisdictional standards. SA Power Networks has indicated that, absent a step change in the standards, expenditure would be similar over the 2020 – 2025 period ($27 million over five years).[39] Without this investment, average reliability would decline by less than one per cent, and reduce a typical residential electricity bill by approximately $1 per annum over the 2020 – 2025 period.[40]

With the exception of this $25 million, SA Power Networks' expenditure is, in the first instance, identified as being required to meet other legal and regulatory requirements, including the suite of National Electricity Rules, and the design, technical, and safety standards brought together in annual SRMTMPs. The Commission recognises that individual expenditure items often serve dual purposes – for example, repair and replacement deliver both safety and reliability outcomes.

[38] For example, in the Directions Workshops conducted by SA Power Networks in 2017, just under 20 per cent of customers indicated a preference for reduced investment in network reliability and resilience.

[39] SA Power Networks 2018, Customer Engagement Workshop, Capital Expenditure Deep Dive Part 2.

[40] The cost for a typical residential bill would be $1.35, assuming a 50-year asset life, and a discount rate of seven percent.

2.3.1.2 A majority of customers are satisfied with current levels of reliability

In the customer survey commissioned for this Review, the majority of customers (73 percent) were either satisfied or very satisfied with reliability of electricity supply to their home or business. A further 15 percent were neither satisfied nor dissatisfied, with 12 percent dissatisfied or very dissatisfied.[41]

Though levels of satisfaction remain high, they have dropped in relation to levels reported in in 2013 (88 percent), 2007 (84 percent) and 2003 (85 percent).[42]

Metropolitan customers reported higher satisfaction than non-metropolitan customers and customers on low reliability feeders. These disaggregated results are shown in Table 4.

Table 4: Levels of satisfaction with reliability of electricity supply to home or business, for metropolitan, non-metropolitan and low reliability feeder customers

	Very satisfied	Satisfied	Neither	Dissatisfied	Very dissatisfied	Refused or don't know
Metropolitan – residential	25%	54%	16%	4%	1%	0%
Metropolitan – business	18%	53%	13%	14%	3%	0%
Non-metropolitan – residential	20%	49%	14%	14%	2%	0%
Non-metropolitan – business	20%	48%	16%	11%	5%	0%
Low reliability feeder – residential	9%	44%	27%	15%	6%	0%
Low reliability feeder – business	25%	54%	16%	4%	1%	0%

2.3.1.3 No clear economic benefit in setting targets to improve performance

Previously, the Commission has regarded customer satisfaction and legal requirements in its decisions on whether to set network performance targets to reduce, improve, or maintain performance. The Commission's 2015 decision noted AEMC recommendations to have regard to economic assessment in the decision-making process.[43]

In this Review, economic assessment was completed for several cost-value scenarios (summarised in Appendix 2). All are scenarios for reliability improvements, with costs and reliability impacts provided by SA Power Networks. The baseline for these scenarios is maintaining reliability at current levels.[44]

[41] Error bands for these results, at a 95 percent confidence level, are 3.1 percent for residential responses and 5.6 percent for business responses.

[42] Figures represent the proportion of customers reporting being either 'very satisfied' or 'quite satisfied' with their electricity supply reliability. The Commission conducted the 2003 and 2007 customer surveys, and SA Power Networks conducted the 2013 survey. There are limitations in comparing the results of these surveys, relating to question design and sample size.

[43] AEMC, Review of the National Framework for Distribution Reliability Final Report, 2013, http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-national-framework-for-distribution

[44] Maintaining reliability at current levels was taken as the status quo for the economic assessment. Consideration was given to the matter that introducing region-based categories may change costs of maintaining reliability. This is possible because in smaller, region-based categories, there is less potential for lower cost improvements in high-density areas to offset higher cost maintenance or improvements in low-density areas. However, a change in costs driven by introducing region-based categories would not be immediate, as no decline in regional performance has been observed since introducing feeder

The scenarios are based on reducing interruption frequency (USAIFI) by one, five and 10 percent. Interruption frequency was chosen as the basis for the scenarios because it can be impacted directly and predictably by capital investment. When interruption frequency (USAIFI) is reduced, interruption duration (USAIDI) also falls.

Scenarios were constructed for reliability improvements for metropolitan customers, non-metropolitan customers, and customers on low reliability feeders. This design responded to:

- concerns raised in SA Power Networks' customer engagement about the difference in reliability experienced by metropolitan customers, non-metropolitan customers, and customers on low reliability feeders.
- this Review's concern that design of the STPIS may through time inadvertently produce a decline in reliability in lower density areas, and the possibility of responding to this by tightening some performance targets.

The CBD was excluded from the cost-value scenarios. This was because performance targets for the CBD are already tight and, at USAIDI of 15 minutes, leave little room for improvement. This Review is separately considering the implications of recent poor performance in the CBD (USAIDI targets have been exceeded for two consecutive years, 2016-17 and 2017-18), and implications of growth of the CBD beyond the Adelaide Business Area for establishing CBD performance targets (see section 2.2).

Benefits were quantified using two different methods: a contingent valuation study, commissioned for this Review, and desktop analysis based on Australian Energy Market Operator (AEMO) estimates of value of customer reliability (VCR).

Assessments of the cost-value scenarios have explicitly examined the cost of providing specific types of service against the value customers place on that service. Results, which show no clear economic benefit in setting targets to improve reliability performance, are summarised below.

2.3.1.4 Contingent valuation results

Contingent valuation is an economic valuation technique for quantifying the value of non-market goods or services, such as reliability improvements, for input into economic assessment.

The Commission engaged consultants Oakley Greenwood and Wallis Market Research to complete an economic assessment using a contingent valuation study for this Review. (Detail on this method, reasons for selecting it, and results are discussed further in Appendix 3, and in the accompanying Oakley Greenwood report).

Results show that only one reliability improvement scenario has a net benefit: an average 10 percent reduction in interruption frequency (associated with a 90-minute annual average reduction in outage duration) for the 27,000 customers on low reliability feeders. This scenario has a net annual benefit of $1.9 million, equivalent to 0.05 percent of SA Power Networks' recoverable revenue for the current 2015 – 2020 period.

The benefits arise from a minority of customers. Two-thirds of the 27,000 customers on low reliability feeders who would benefit directly from these improvements are not willing to pay anything at all for the improvement. This is consistent for both residential (62 percent) and business customers (66 percent). [45] A potential explanation is that some low reliability feeder customers may have contingency plans (including on-site generation).

category targets in 2015. Such decline would only be expected to occur over the medium to long term. Cost changes would arise in incremental decisions about repair and replacement expenditure.

[45] Error bands for these results, at a 95 percent confidence level, are 6 percent for residential responses and 11.8 percent for business responses.

Likewise, there are customers who would not benefit directly who do not want to subsidise this improvement. Some customers in metropolitan areas are not willing to subsidise improvements for low reliability feeder customers (54 percent of residential, and 52 percent of business), nor are some customers in non-metropolitan areas (38 percent of residential, and 52 percent of business).[46]

2.3.1.5 Value of customer reliability (VCR) analysis results

Value of customer reliability refers to the amount of money a customer would be willing to pay to avoid a supply interruption. The most recent set of values were prepared by AEMO in 2013-2014.[47]

For this Review, desktop analysis based on AEMO estimates of VCR was conducted. (Detail on this method and results are discussed further in Appendix 3).

Though results using contingent valuation suggest a small economic benefit in setting targets to facilitate a 10 percent reduction in outage frequency for customers on low reliability feeders, these results are not mirrored in results of the VCR analysis. Using the VCR analysis, the same scenario has a net cost of $1.6 million.

The Commission has concluded that results of economic assessment show no clear economic benefit in setting targets to improve reliability performance.

2.4 Targeted improvements for specific regions

The draft decision is to not set standards to achieve targeted improvements in specific regions.

As discussed in section 2.2.3, one reason for introducing region-based categories is to provide a basis for targeted improvements in specific areas where a rationale exists. The Commission has considered whether targeted improvements in specific areas are justified for the 2020-25 period.

Areas of recent concern have been the Eyre Peninsula and Adelaide Hills. The Commission conducted an Inquiry into the reliability and quality of electricity supply on the Eyre Peninsula in 2017. [48] Performance in the Adelaide Hills declined in 2016-17 due to the impact of severe weather, particularly the major storms of 27 and 28 December 2016. [49]

To examine the case for targeted improvements, this Review conducted an assessment of improvements for each of the regions proposed in this draft decision, using desktop VCR analysis. This analysis was based on cost-value scenarios developed by SA Power Networks for each region (included in Appendix 2).

Results show small, but somewhat uncertain, net benefits for a one percent reduction in outage frequency in three regions, and net costs for other regions (detailed in Appendix 3). The Commission's view is that these are not high enough to justify targeted regional improvements.

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46 Note the error bands that apply to these results, which are set out in Appendix 3, Table 9.

47 See the AEMO Value of Customer Reliability project page: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.The AEMC is considering a rule change request to make the AER responsible for calculating values of customer reliability, see https://www.aemc.gov.au/rule-changes/establishing-values-of-customer-reliability

48 Essential Services Commission of South Australia, October 2017, Inquiry into the Reliability and Quality of Electricity Supply on the Eyre Peninsula, https://www.escosa.sa.gov.au/ArticleDocuments/1086/20171027-Inquiry-ReliabilityQualityOfElectricitySupplyEyrePeninsula-Final.pdf.aspx?Embed=Y

49 Essential Services Commission of South Australia, June 2017, Distribution Licence Compliance Review of SA Power Networks in relation to the 27-28 December 2016 severe weather event, https://www.escosa.sa.gov.au/ArticleDocuments/1054/20170623-Electricity-SevereWeatherEvent27-28Dec2016-DistributionLicenceComplianceReview-SAPN.pdf.aspx?Embed=Y

2.5 Standard of endeavour: absolute targets or a degree of flexibility?

The draft decision is that:

1. SA Power Networks' performance targets (for network performance and customer service) will continue to be of a 'best endeavours' nature.
2. SA Power Networks must publish an annual Monitoring, Evaluation and Compliance Strategy (MECS) that outlines its strategy for applying its best endeavours.
3. SA Power Networks must publicly report on how it has applied its best endeavours where it misses performance targets, and following significant performance events.
4. To support the revised reporting accountability, the Commission will continue to conduct periodic assessments of the systems, processes and controls used by SA Power Networks to prepare and provide those reports, including the underlying data quality.
5. The Commission will also continue to issue long-term industry performance trends and statistics, and will also provide analysis of key events or compliance matters as necessary.

The Commission expects SA Power Networks to take a proactive approach to best endeavours, clearly set out how it will apply its best endeavours, and, explain its performance when it misses targets and following significant performance events.

The annual Monitoring, Evaluation and Compliance Strategy (MECS) should outline what it means to apply best endeavours. The aim is to remove the ad hoc nature of best endeavours assessments, and increase the direct accountability of SA Power Networks to its customers and stakeholders.

The strategy should be supported by and link policies, procedures, systems and plans. These may include existing documents, such as annual SRMTMPs, existing procedures (such as emergency response procedures) and protocols (such as that for notifications when force majeure conditions are declared). The SA Power Networks' Board should endorse the MECS.

SA Power Networks should use the MECS as a point of reference for its public reporting on how it has applied its best endeavours, following a missed performance target or significant performance event.

2.5.1 Existing arrangements

Currently, SA Power Networks' performance targets (for network performance and customer service) are of a best endeavours nature. Further, best endeavours is the standard required of SA Power Networks in significant performance events, currently defined as MEDs.

The term best endeavours is defined in the Code as 'to act in good faith and use all reasonable efforts, skill and resources.' The Commission monitors and reports on its assessment of how SA Power Networks exercises its best endeavours in each year of the regulatory period.

A best endeavours obligation is not as onerous as an absolute obligation (like 'must' or 'shall'). It requires that SA Power Networks do what is prudent and reasonable in the circumstances. Though best endeavours does not require effort that goes beyond the bounds of reason, is considerably more than casual and intermittent activities. It means acting honestly, reasonably and making a positive effort to perform the relevant obligation.

Currently, in reporting to the Commission SA Power Networks must set out if performance targets have been met, and if not, why not. Explanations are expected to provide sufficient information to enable the Commission to form a view as to whether or not best endeavours were employed.

Explanations might include, for example, what action was taken to avoid targets being missed, when that action was taken, preparations prior to events (such as internal procedures and protocols set for handling such instances, the level of planning and the ability to call on additional resources when required), and any subsequent improvements implemented.

The Commission then applies a best endeavours assessment. This is a subjective assessment of SA Power Networks' explanation. In this assessment, the Commission takes into account:

- reasons for failing to meet the target
- the magnitude by which the target was missed (noting that an assessment is still performed, even if the target is narrowly missed)
- if the circumstances were reasonably foreseeable or beyond SA Power Networks' control
- remedial action undertaken in response to the missed target
- improvements in performance throughout the year
- long-term trends in performance
- the extent to which SA Power Networks has engaged with Commission staff, and
- the quality of information provided.

The Commission approaches enforcement in line with its Enforcement Policy 2013.[50]

2.5.2 Rationale

There are several reasons for this draft decision.

First, continuation of the best endeavours standard reflects the fact that factors outside of SA Power Networks' control can influence network performance. Second, it allows the Commission discretion in deciding if SA Power Networks' performance is acceptable on a long-term basis, and in selecting enforcement measures. Third, placing responsibility to set out, ahead of time, what it means to apply best endeavours (through the MECS) will improve SA Power Networks' accountability.

In preparing the MECS, and subsequent explanations of performance, SA Power Networks will be responsible for deciding what level of explanation is required. Statements may include technical actions, consideration of costs of improvements, and evidence on whether or not these are acceptable to customers. Where remedial actions are required, the Commission expects that SA Power Networks will incorporate progress on those actions into its reporting.

In the course of this Review, the Commission considered alternative improvements to the best endeavours approach. These included:

- Replacing 'best endeavours' standards with absolute performance targets to apply in normal operations.

  This approach is not preferred because, even with a clear compliance/enforcement strategy, a level of discretion similar to that existing with the current approach would have to remain. Further, the Commission is aware that absolute performance targets can be a more costly approach to risk mitigation.

[50] Essential Services Commission of South Australia, 2013, Enforcement Policy Version 2.5, see https://www.escosa.sa.gov.au/ArticleDocuments/580/130905-EnforcementPolicy_V2-5.pdf.aspx?Embed=Y

- Defining a tolerance band around each target, within which best endeavours would be automatically be met.

  This was considered because performance targets are set based an average of five years' performance and some variation around that average can reasonably be expected.

  However, where performance targets are set based on an average of five years' performance and there is variation, reasons for that variation can still be set out. Although variation may be reasonably expected, SA Power Networks must help customers understand variation, particularly whether it is the start of a systemic performance issue. One way to illustrate this is to make comparisons with longer-term performance.

2.6 Performance during significant events: included or excluded?

The draft decision is to set targets for normalised performance, and separately consider performance during significant events, currently defined as MEDs.

Implementation of this draft decision will require reviewing the methodology currently used to normalise performance data, to consider its application to region-based categories.

This draft decision continues the existing arrangement, where targets are set for normalised performance. Currently, SA Power Networks normalises outages by excluding the impact of MEDs. This arrangement was introduced in 2015.

MEDs are days on which reliability performance across a network is more than 2.5 standard deviations from the mean, as identified using the natural logarithm methodology developed by the Institute of Electrical and Electronics Engineers (IEEE). [51] The same methodology is used to normalise SA Power Networks' performance data for the STPIS.

2.6.1 Rationale

Setting targets for normalised performance excludes some events that are beyond SA Power Networks' control, but still requires it to plan for risk and uncertainty. The Commission considers that this continues to be important.

However, continuing to normalise performance to assess against region-based targets will require reviewing the current methodology to assess whether it is fit for purpose. In its submission to the Objectives and Process paper, SA Power Networks states:

> 'The exclusion of MEDs is an effective method for normalising the performance of the whole distribution network (ie at a state-wide level)…. However, it is not as effective for normalising reliability at a sub-distribution network level (eg regional), as a localised severe weather event (SWE) can significantly affect the reliability at sub-distribution network level but not be classified as a MED. These localised SWEs must be excluded at a sub-network level to enable effective monitoring of underlying (ie normalised) reliability at that level. Consequently, if the Commission was to impose reliability standards on a regional basis (ie sub-network level), a different normalisation method would need to be adopted, to monitor underlying reliability at a regional level.

In joint workshops held as part of the Review process, SA Power Networks proposed an alternative methodology to remove days of outlying performance on a regional basis. The Commission will work with SA Power Networks to develop and consult publicly on an acceptable methodology ahead of 1 July 2020.

[51] Institute of Electrical and Electronics Engineers (IEEE) standard 1366-2012.

2.7 Other exclusions: revised to be consistent with STPIS reporting

The draft decision is to revise other exclusions from performance to be consistent with exclusions in the STPIS, following the final decision of the STPIS review, due in mid-2018.

The Code currently defines an interruption as 'a planned or unplanned interruption of, or restriction to, distribution services of at least one minute in duration, other than an interruption or restriction due to an emergency, a generation failure or a transmission failure'. This is in addition to exclusion of performance during significant events.

2.7.1 Rationale

This change will improve regulatory consistency. The AER is revising its basis for recording an interruption as part of its current STPIS review. The proposed exclusions (set out in Appendix 4) are broadly consistent with the Code's current definition of an interruption, with the exception of the change in definition of momentary interruption from one minute to three minutes.

With regard to the three-minute momentary interruption definition, the AER's rationale behind the proposed shift from one-minute is that it would promote use of feeder automation to avoid longer outages.[52] This change arises from a recommendation from the 2014 AEMC Review of Distribution Reliability Measures.[53]

While a one-minute definition promotes use of established technologies like reclosers, the three-minute definition promotes newer technology, such as feeder automation. Both definitions promote momentary interruptions instead of longer interruptions, but extending the definition to three minutes allows use of a wider range of technologies.

The Commission acknowledges the concern of S&C Electric expressed in its submission to the Objectives and Process paper, that momentary interruptions are inconvenient to customers, particularly business customers, and pose a challenge to the use of distributed energy resources.[54]

The Commission's view is that widening the definition will not promote momentary interruptions, but instead promote potentially long interruptions being 'turned into' momentary interruptions. That is, the frequency of interruptions will remain the same, but duration of interruptions will fall, reducing overall inconvenience to customers.

[52] AER, 2017, Draft amended STPIS explanatory statement, p. 10

[53] AEMC, 2014, Review of Distribution Reliability Measures, see https://www.aemc.gov.au/markets-reviews-advice/distribution-reliability-measures

[54] S&C Electric submission

3 Guaranteed service level (GSL) scheme

This section addresses the second of the reliability standard framework's four main elements: the GSL scheme. The GSL scheme acknowledges the inconvenience customers experience when SA Power Networks does not meet its service obligations.[55]

There are currently five types of GSL payment. Two relate specifically to network reliability. These are duration of interruption payments (**duration payments**) and frequency of interruption payments (**frequency payments**). The remainder relate to other elements of service: late attendance at appointments, delays to providing new connections, and delays in fixing street lights where customers report outages.

3.1 Payments for network reliability will continue

The draft decision is to continue GSL payments for network reliability, with improvements as set out in the remainder this section.

There are currently two GSL payments that relate specifically to network reliability: duration payments and frequency payments. The central objective of these payments is to acknowledge that 'some of the worst served customers are unlikely to receive future service improvements due to the high costs of improving their supply'.[56]

3.1.1 Rationale

This draft decision is based on evidence that customers value GSL payments for network reliability.

Respondents to the customer survey conducted for this Review were asked about their willingness to pay for duration payments (which account for 97 percent of GSL scheme costs). Results showed that in aggregate, customers are willing to pay $6.4 million per annum for this type of payment (an average of $7 per year, per customer).

The survey framed duration payments as 'inconvenience payments'. Asking about 'inconvenience payments' was important, because, in their current form, this is essentially what duration payments are.

Currently, duration payments are poorly targeted to the customers identified in the scheme's objective: those 'unlikely to receive future service improvements due to the high costs of improving their supply'. A large proportion of payments are made to customers who experience a one-off outage, but typically have average or good reliability. (This is discussed further in section 3.2.1).

Further, it was important for the survey to be clear that duration payments are simply for 'inconvenience'. Duration payments are broadly perceived as providing compensation for outages.[57] This is incorrect – GSL payments are not insurance, and not intended to be compensatory.[58] GSL payments are also not hardship payments. They are not directed to customers who may need hardship payments.

[55] Electricity Distribution Code 12.1, section 2.3

[56] Essential Services Commission of South Australia, April 2005, 2005-2010 Electricity Distribution Price Determination Part A: Statement of Reasons.

[57] According to SA Power Networks' customer engagement, as reported in a presentation to the Review's joint workshop on GSL payments, October 2017.

[58] SA Power Networks has a separate compensation scheme that may apply customers who have incurred economic loss as a result of negligence by SA Power Networks.

In asking about willingness to pay for duration payments, the customer survey explained that: 'The purpose of the payments is to acknowledge that power outages are inconvenient. The payments do not provide direct compensation for any damages or losses the customer experiences due to the outage'.[59]

Survey responses indicated marginal support for continuing with duration payments, with 52 percent of customers valuing the payments, 42 percent not willing to pay anything and six percent not knowing.[60] The contingent valuation based on survey results found that in aggregate, customers are willing to pay $6.4 million per annum for this type of payment (an average of $7 per year, per customer).

Reviewing GSL payments with regard to customer's willingness to pay is consistent with STPIS rules, which is relevant as the STPIS includes a GSL scheme. Though the scheme does not apply in South Australia (it would only apply in the absence of a jurisdictional scheme), it has been used in this Review for guidance.

Section 6.2 (c)(3) of the STPIS states that any individual parameter (such as duration or frequency payments) should not apply where its cost is likely to be greater than the cost customers are willing to pay for its inclusion.

3.2 Duration payments for one-off outages removed

The draft decision is to remove duration payments in their current form. Duration payments for one-off outages will be replaced with total annual duration payments, to apply at the end of each regulatory year.

Currently, five levels of duration payment apply for one-off outages. Values range from $100 for interruptions more than 12 and up to 15 hours long, to $605 for interruptions longer than 48 hours.

3.2.1 Rationale

There are three reasons for the draft decision to remove duration payments in their current form.

First, duration payments for one-off outages do not effectively target customers experiencing ongoing and persistent reliability issues. Though payments are made to these customers, they are also made to customers who typically have average or good reliability.

This is illustrated by the fact that, since 2010, only 37 percent of duration payments (accounting for 24 percent of payment value) went to customers on low reliability feeders. Further, since 2010, 53 percent of duration payments (accounting for 87 percent of payment value) related to outages on MEDs.

Second, current levels of duration payments are not a strong driver of SA Power Networks' response to interruptions. Providing a signal for prompt restoration of power is a secondary objective of duration payments.[61]

Following an unplanned interruption, SA Power Networks is obliged, by the National Energy Retail Rules, to use its best endeavours to restore supply to all customers as soon as possible.[62] In this context, SA Power Networks prioritise safety, then restoring power to high voltage lines.

[59] The customer survey is included in full as Appendix A of the attached Oakley Greenwood Final Report.

[60] Error bands for these results, at a 95 percent confidence level, are 3.1 percent for residential responses and 5.6 percent for business responses.

[61] Essential Services Commission of South Australia, 2008, South Australian Electricity Distribution Service Standards 2010-2015, Final Decision

[62] National Energy Retail Rules, Part 4, 91 c

It then restores power to customers in line with priorities agreed with the SA Government. [63] These are:

1. State electricity grid
2. Communications
3. Water for drinking
4. Wastewater
5. Hospitals, aged care
6. Bulk transport
7. Major shopping centres
8. Emergency services control centres
9. Correctional services
10. Major industrial customers
11. Residential customers.

SA Power Networks then considers where it can restore the most customers in the shortest time, before turning its attention to those most likely to be off-supply for the longest period.

The lowest duration payment threshold (12 hours) provides a weak restoration incentive in that context. While the incentive is stronger when larger number of customers are affected, in those situations managing GSL costs are not the primary consideration, as SA Power Networks works according to the hierarchy set out above.

Third, results from the customer survey indicate that customers are willing to pay less for duration payments than they do now, and that only 52 percent of customers are willing to pay anything for duration payments.[64] Removing duration payments for one-off outages will reduce the total cost of the GSL scheme, and so the costs recovered from customers.

The survey found that in aggregate, customers are willing to pay $6.4 million per annum for duration payments (an average of $7 per year, per customer). This is less than the $10.1 million per annum ($12 per year, per customer) recovered from consumers through distribution tariffs, but similar to the average cost of the GSL scheme over the last 12 years, $5.1 million (nominal).[65]

As the $10.1 million per annum ($12 per year, per customer) was presented as the status quo in the customer survey, a valid interpretation of survey results is that customers are willing to pay less than they do now. The survey explained that paying less than the status quo would 'mean the payments would be smaller, or fewer people would get them'.

The difference between the $10.1 million per annum for the 2015 – 2020 and the actual cost of the scheme highlights how the AER provides for GSL expenditure. The allowance for the 2015 – 2020 period was made with reference to the 2013-14 base year, a year in which GSL payments were the highest to date. However, the average cost up until that time (from 2005-06 to 2012-13) was lower; $2.3 million. Costs of GSL payments in the current period have continued to be highly variable ($2.5 million in 2015-16 and $28.4 million in 2016-17).

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[63] Essential Services Commission of South Australia, June 2017, Distribution Licence Compliance Review of SA Power Networks in relation to the 27-28 December 2016 severe weather event, pp. 16-17, see https://www.escosa.sa.gov.au/ArticleDocuments/1054/20170623-Electricity-SevereWeatherEvent27-28Dec2016-DistributionLicenceComplianceReview-SAPN.pdf.aspx?Embed=Y

[64] Error bands for this result, at a 95 percent confidence level, are 3.1 percent for residential responses and 5.6 percent for business responses.

[65] GSL costs are included in SA Power Networks' operating expenditure allowance determined by the AER. The most recent operating expenditure allowance was set with reference to 2013-14 as a base year, in which the AER reported GSL payments of $10.1 million (see AER, October 2015, Final decision, SA Power Networks determination 2015-16 – 2019-20, Attachment 7, p. 64).

Though the improvements proposed in this draft decision will manage the absolute cost of the GSL scheme, its costs will still be highly variable. Marked differences between individual years will continue. How to provide for this in revenue determinations is an important consideration for the AER.

3.3 Total annual duration payments introduced

The draft decision is to introduce total annual duration payments that will apply at the end of each regulatory year, and will include outages on major event days.

Total annual duration payments will replace duration payments for one-off outages, and will apply at the end of each regulatory year. They will apply in relation to all outages over the course of a year, including those during significant performance events (currently defined as MEDs). Three levels of payment are proposed, as shown in Table 5.

Table 5: Thresholds and values of proposed total annual duration payments

Threshold	Value
> 20 and ≤ 30 hours	$100
> 30 and ≤ 60 hours	$150
> 60 hours	$300

3.3.1 Rationale

The central reason for introducing total duration payments is that they will better target customers experiencing ongoing and persistent reliability issues, for whom high per customer costs may prevent improvements. This is the stated objective of the current GSL scheme.

Total duration payments will not apply in relation to outages for one-off events over which SA Power Networks has limited control (although a one-off outage of more than 20 hours would trigger an end-of-year payment).

Considerations in establishing the range total duration payment values should sit within included:

- Containing total scheme cost within the amount that customers are willing to pay ($6.4 million per annum), noting the inherent variability of scheme costs.

  Through the average annual cost of the GSL scheme over the twelve years from 2005-06 is $5.1 million, this has been highly variable. The year with the highest cost was 2016-17 ($28.4 million), and those with the lowest cost were 2007-08 and 2008-09 (each $0.5 million). The average cost of the scheme since 2005-06 excluding 2016-17 was $2.98 million. The bulk of costs are for duration GSL payments (on average, 97 percent).[66]

- Containing payment values within the annual distribution costs included in a typical residential bill (approximately $545 per annum).[67]

- Values calculated with reference to the AEMO VCR (these would be $460, $700 and $1390 respectively), noting the AEMO VCR application guide notes limitations in the use of VCR for long outages. [68]

[66] Values are nominal, as reported to the Commission by SA Power Networks each year for the last 12 years.
[67] Figure based on quarterly distribution network charges figure provided by SA Power Networks of $136, for a residential customer consuming 1250 kWh per quarter.
[68] Values calculated for a residential customer consuming 1250 kWh per quarter, using a VCR of $40.62 per kWh.

With these considerations in mind, the thresholds and values for total duration payments set out in Table 5 are based on those in the STPIS scheme.[69]

Total duration payments also apply in Victoria, with the same thresholds and slightly higher values ($120, $180 and $360).[70] The STPIS has been reviewed more recently (underway, with no GSL value changes proposed) than the Victorian scheme (last reviewed in 2015).[71]

The threshold structure for total duration payments also recognises very long outages. While the highest threshold for current one-off duration payments is > 48 hours, the highest threshold for total annual duration payments is > 60 hours.[72]

3.3.1.1 Why not payments for one-off outages, too?

In the STPIS and Victorian GSL schemes, where total duration payments apply, payments for one-off outages apply too.[73]

In Victoria, payments for one-off outages were introduced to complement total duration payments in 2015. (Prior to 2015, the scheme contained total duration payments alone). The Essential Services Commission of Victoria set out the merits of including both:

> 'By including the duration of individual interruptions in the Victorian GSL payments scheme, there would be a stronger incentive for the electricity distributors to avoid long interruptions and aligns the Victorian GSL payments scheme with the national GSL payments scheme. As very few payments are likely to be made, the cost impact is immaterial.'[74]

This Review considered applying both duration and total duration payments. This has been decided against because in South Australia, now, duration payments do not provide a strong incentive for timely restoration of power. They are also not well targeted to customers with ongoing and persistent reliability issues (see section 3.2.1). Further, unlike in Victoria, the number and cost of payments for one-off outages is substantial (though variable).

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69 AER 2017, Draft Amended Service Target Performance Incentive Scheme, p. 21, see https://www.aer.gov.au/system/files/AER%20-%20Draft%20amended%20service%20target%20performance%20incentive%20scheme%20-%20December%202017.pdf

70 Essential Services Commission of Victoria, 2015, Review of the Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme, Final Decision, https://www.esc.vic.gov.au/sites/default/files/documents/721d99ec-9f7d-4bdd-af7c-6e88647a64b1.pdf

71 A review is also currently underway in Queensland. The consultation paper includes a useful summary of GSL schemes that apply in each jurisdiction. See: Queensland Competition Authority, Review of Guaranteed Service Levels to apply in Queensland from 1 July 2020, consultation paper, http://www.qca.org.au/getattachment/3e6ec027-2ad3-4e3c-be1d-d9c22141abdf/QCA-GSL-Review-consultation-paper.aspx

72 Following the December 2016 storms, the then Minister for Energy and Mineral Resources asked the Commission to examine whether the GSL scheme should be expanded to include increased payments for power interruptions more than three days (72 hours) long. In considering this, this Review found that very few single unplanned interruptions last longer than 72 hours. There would have been 1001 payments for a 72-hour plus threshold following the December 2016 storm (out of the total 65,227 duration payments). From 2010-11 to 2012-13 there were, on average, only six duration payments made each year for interruptions longer than 72 hours.

73 In the STPIS, total annual duration payments apply in addition to duration payments for one-off outages longer than 12 hours (on CBD and urban feeders) or 18 hours (on rural feeders). In Victoria, duration payments for one-off outages only apply up until the point where a customer has experienced 20 hours or more of unplanned interruptions in a year.

74 Essential Services Commission of Victoria, 2015, Review of the Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme, Final Decision, pp. 30-31, https://www.esc.vic.gov.au/sites/default/files/documents/721d99ec-9f7d-4bdd-af7c-6e88647a64b1.pdf

3.3.1.2 Why not limit the scheme by excluding MEDs?

The Review considered an alternative way of better targeting customers with ongoing and persistent reliability issues: making outages due to significant performance events, currently defined as MEDs, ineligible for GSL payments.[75]

Both the STPIS scheme and the Victorian GSL scheme exclude outages on MEDs, though they each use a different methodology.[76,77]

Several submissions to the Objectives and Process paper supported this approach, on the basis that it would remove outages over which SA Power Networks has limited control, and help manage the cost of the scheme.

This option was presented in the customer survey. Customers were asked whether they would support removing GSL payments for long outages due to major storms, on the basis that it would reduce annual costs of the GSL scheme from $12 per customer to $2 per customer. Results were inconclusive: 45 percent of customers would not support this change, 41 percent would, and 14 percent did not know.

A further consideration was how this exclusion could be communicated to customers. The recent experience of South Australian customers in understanding exclusions due to outages caused by transmission and generation failure, and emergency circumstances, highlights the potential communication challenge.[78]

In 2015, the Essential Services Commission of Victoria considered excluding outages on MEDs using the methodology SA Power Networks applies now (the same as that used in the STPIS scheme). It noted that:

> 'A communications campaign would also be needed to educate customers as to why they are not eligible for a GSL payment even though they may have experienced many interruptions or long periods of time off supply.'[79]

The Essential Services Commission of Victoria decided to continue excluding outages on MEDs using a methodology that excludes very few outages (outages on around one day every five years). [80]

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75 Part of the rationale for considering this is that SA Power Networks has limited ability to control payments that relate to MEDs, through either capital investment or operational decisions. As SA Power Networks has limited ability to predict which area severe weather will affect, it cannot predict where the majority of GSL payments will be required. If SA Power Networks chose to undertake widespread network investment, or increased operating expenditure, to manage GSL payments on MEDs, the costs would far exceed the benefits.

76 STPIS section 6.4 (a) (b)

77 Essential Services Commission of Victoria, 2015, Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme – Final Decision, p. 64, see https://www.esc.vic.gov.au/sites/default/files/documents/721d99ec-9f7d-4bdd-af7c-6e88647a64b1.pdf

78 In addition to exclusion of outages caused by transmission or generation failure, outages (or parts of outages) are excluded when SA Power Networks cannot gain safe access (see section 2.3.2 of the Code). Due to the exclusion of outages caused by transmission and generation failure from the GSL scheme, SA Power Networks was not required to make payments for some recent notable outages, including the 28 September 2016 state-wide outage and the rotational load shedding of 8 February 2017. Due to limited access in emergency circumstances, SA Power Networks was not required to make payments for all outages that resulted from the December 2016 storms. Complaints to the Energy and Water Ombudsman of South Australia regarding GSL payments increased from 13 in 2015-16 to 138 in 2016-17.

79 Essential Services Commission of Victoria, 2015, Review of the Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme, Draft Decision, p. 70, see https://www.esc.vic.gov.au/sites/default/files/documents/221ab36d-3eab-42b4-847d-89342d68096f.pdf

80 Essential Services Commission of Victoria, 2015, Review of the Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme, Draft Decision, p. 68,see https://www.esc.vic.gov.au/sites/default/files/documents/221ab36d-3eab-42b4-847d-89342d68096f.pdf

3.4 Frequency payments simplified

The draft decision is to consolidate frequency payment thresholds to one level: more than nine outages per annum.

Currently, there are three levels of frequency payment. Values range from $100 for more than nine and up to 12 interruptions in a year, to $200 for more than 15 interruptions in a year.

The design of frequency payments means they relate to reliability over time, starting with payments for customers who experience more than nine interruptions. This makes them well targeted toward customers who experience ongoing or persistent reliability issues.

The rationale for this draft decision is that it will simplify this payment type, making it easier for customers to understand and more straightforward to administer.

The value that will apply is $100 for more than nine outages per annum. In selecting this value, this Review has had regard to:

- Containing the overall cost of the GSL scheme, as set out in section 3.1.1 and 3.2.1.
- The current value of frequency payments in the South Australian scheme ($100 - $200, depending on the number of interruptions).
- The value of frequency payments in the STPIS scheme, as the most recently reviewed of the Australian GSL schemes ($80, for more than nine interruptions on CBD or urban feeders, and for 15 or more interruptions on rural feeders).

Cost estimates for proposed total duration and frequency payments are addressed in Box 3.

Box 3: Cost of proposed total duration and frequency payments

The scheme set out in this draft decision is designed with a view to containing scheme costs with respect to the willingness to pay expressed in the customer survey, $6.4 million per annum.

With the proposed enhancements, the cost of the reliability GSL payments will still be highly variable. For example, if the revised scheme had applied in 2016-17, total duration and frequency payments are estimated to have cost $16.4 million (compared with $28.4 million for the duration and frequency components of the current GSL scheme).[81]

If it had applied in 2015-16, total duration and frequency payments are estimated to have cost $1.45 million (compared with $2.3 million for the duration and frequency components of the current GSL scheme).[82]

These estimates are based on analysis by the Commission and SA Power Networks. The Commission is seeking a submission from SA Power Networks about the cost of the proposed scheme, had it applied over the 2005-06 to 2016-17 period (the life of the reliability GSL payments).

The revised payments have the effect of capping payments to any one customer, in any one year. The maximum amount any one customer can receive based on total duration of interruption is $300 per annum. They may also receive a frequency payment ($100), if eligible, making a total of $400 per annum.

[81] Costs of total duration payments are estimated as $16.0 million, and frequency payments at $0.40 million.
[82] Costs of total duration payments are estimated as $1.40 million, and frequency payments at $0.05 million.

3.5 Restoration targets reinstated

The draft decision is to reintroduce annual average restoration time targets, as applied pre-2010, for each region.

Restoration targets will take the form of '80 percent of customers restored within two hours, 90 percent of customers restored within three hours', for each region-based category.

Targets will be established to maintain current performance. They will exclude ten per cent of outages, to allow for restorations that require substantial capital works. Targets will vary for each region, to allow for longer restoration times in regions with fewer depots and/or longer travel times.

There are currently no restoration targets in the reliability standards framework. Annual average restoration time targets were removed in 2010.[83] At that time, the Commission that considered restoration targets:

- provided a weak incentive for SA Power Networks to promptly restore power compared with other measures (ie duration payments)
- provided little meaningful information to customers, and
- did not improve national consistency.

3.5.1 Rationale

Restoration targets are proposed as an alternative to the weak signal for timely restoration currently provided by duration GSL payments. There is no proposal to link GSL payments, or other financial incentives, to these restoration targets. Restoration targets will complement the existing signals described in section 3.2.1.

Restoration targets will help customers understand what they can expect from SA Power Networks when outages occur. They will be a unique part of the reliability standard framework in that they are a measure of reliability that only reflects the experience of customers who have outages (ie that is not averaged across the whole customer base).

3.6 Late attendance at appointments

The draft decision is to remove the GSL payment for late attendance at appointments.

Currently, a payment of $25 applies if SA Power Networks is more than 15 minutes late for an appointment, unless due to circumstances beyond its reasonable control.[84]

3.6.1 Rationale

SA Power Networks makes few payments for late attendance at appointments. It made one late attendance payment in 2016-17 and two in 2015-16. This is because SA Power Networks rarely offer a specific appointment time for any work. When appointments are booked, they have long windows (eg six-hours, or morning/afternoon). Further, late attendance for connection appointments is captured under the 'timeliness of new connection' GSL payment.

[83] Essential Services Commission of South Australia, 2008, South Australian Electricity Distribution Service Standards 2010-2015, Final Decision, section 4.1.3

[84] Electricity Distribution Code 12.1, section 2.3.1(a)

3.7 Timeliness of new connections

The draft decision is to continue the GSL payment for timeliness of new connections.

Currently, SA Power Networks is required to use its best endeavours to connect a customer's new supply address on the date agreed with the customer or within six business days of the customer meeting necessary conditions. SA Power Networks is obliged to pay a customer $65 for each day it is late in making a connection, up to a maximum of $325.[85]

3.7.1 Rationale

Changes to this GSL payment may be required as metering contestability changes continue to rollout in South Australia. The Commission will consider changes following resolution of the AEMC Metering Installation Timeframes rule change, which was initiated on 31 May 2018.

By way of background, South Australia is currently experiencing issues with timely installations of meters, resulting in new connections being delayed. This is the result of changes in metering contestability rules, and operation of third party metering providers.

Improvements to metering contestability are currently being negotiated, with discussions occurring between SA Power Networks, electricity retailers, third party metering providers and regulators (including the AER and the Commission).

SA Power Networks is currently applying this GSL payment where there is delay in power being brought to the meter isolator, the boundary of the distribution network, regardless of whether a meter is installed and operating. Premises cannot be electrified until a meter is installed.

3.8 Repair of faulty street light(s)

The draft decision is to remove the GSL payment for repair of faulty street lights.

Currently, SA Power Networks is required to use its best endeavours to repair street lights that have gone out and for which it is responsible within five business days for metropolitan areas, and within ten business days for non-metropolitan areas. It is required to pay the first person to report the faulty street light $25 for each period (five or ten business days depending on its location) in which the street light is not repaired.[86]

3.8.1 Rationale

There are two reasons for the draft decision to remove the GSL payment for repair of faulty street lights (street light payment).

First, the street light payment relates to timeliness of street light repairs, not just to reporting by a customer of a faulty light. The incentive for SA Power Networks to complete street light repairs in a timely manner can be provided by a performance standard (see section 3.9), a mechanism that does not require a payment to customers.

On average, each year from 2000-01 to 2016-17, SA Power Networks has made 1540 street light payments at an annual average cost of $103,000. This cost is met by all SA Power Networks

[85] Electricity Distribution Code 12.1, section 2.3.1(b)
[86] Electricity Distribution Code 12.1, section 2.3.1(c)

customers, through distribution tariffs. This cost can be avoided by removing street light payments and replacing them with a performance standard.[87]

Street light payments have been in place since the Code commenced in 1999. The Commission expects that reporting of faulty street lights by customers will continue to occur, even in the absence of a payment. Since 1999, SA Power Networks has improved the ease of reporting faulty street lights through its website. The Commission will require SA Power Networks to continue recording the number of street light faults reported so changes can be monitored.

Second, SA Power Networks has raised concerns that the street light payment is leading to high levels of reporting by some individual customers, as well as instances of deliberate damage to street lights in order to receive payments. Options to address this considered in making this draft decision have included restricting eligibility. This approach is taken interstate, where street light payments are restricted to occupiers of property neighbouring the street light.[88]

A further consideration has been results from the customer survey. The survey did not include a question on street light payments. However, results on duration payments indicated many customers are unwilling to pay for existing levels of GSL payments.

Previously, the rationale for the street light payment has been described as providing a cost-effective alternative to SA Power Networks conducting street light patrols.[89] The Commission does not have contemporary evidence that the street light payment provides a cost-effective alternative to street light patrols. Given the public good provided by street lights, it may be that customers will report outages, without a payment being required, and without the need for street light patrols.

3.9 Performance standard for timely street light repair

The draft decision is to introduce a performance standard for repair of faulty street lights.

The performance standard will be that SA Power Networks must use its best endeavours to achieve an annual average performance target for repair of street light faults. The target will be will be expressed as a percentage of total faults repaired within five business days (in the CBD, Adelaide metropolitan area, and major regional centres) or ten business days (elsewhere) of SA Power Networks becoming aware of the fault. The target will be set based on historical performance.

3.9.1 Rationale

Expressing performance for timely street light repair as a percentage of total public light faults repaired within defined timeframes (ie five or ten business days) reflects management of simple repairs (eg replacing faulty luminaires) and more complex repairs (eg addressing cable faults).

Complex repairs take longer, and SA Power Networks has raised concerns about high GSL payments in these instances. Under the proposed performance target for timely street light repair, based on average annual performance, individual instances of complex faults will be accommodated, as they will be offset by minor faults which are generally repaired well within the timeframes.

87 The cost of undertaking street light repairs would still be funded by customers, as they are now, though the GSL payment would be avoided.

88 Essential Services Commission of Victoria, 2015, Public Lighting Code version 2, section 2.5, https://www.esc.vic.gov.au/document/energy/29284-public-lighting-code-current-version/

89 Essential Service Commission of South Australia, 2013, SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 regulatory period, Draft decision, p. 34.

This approach to measurement is the basis of the STPIS street light repair parameter. This parameter does not currently apply to SA Power Networks, but is a parameter that the AER may apply where street light repair is defined as a standard control service in a distributor's revenue determination.[90]

For SA Power Networks, public lighting is currently classified as a negotiated distribution service.[91] The AER has indicated its preliminary approach for the 2020 – 2025 period is to classify public lighting services as alternative control services, so it appears unlikely that a street light repair parameter would be included in SA Power Networks' STPIS for the new period.[92]

The proposed performance targets of percentage of total public light faults repaired within five days (in the CBD, Adelaide metropolitan area, and major regional centres) or ten business days (elsewhere), are based on the current timeframes for street light payments.[93]

[90] STPIS section 5.1 (e)

[91] See AER, October 2015, SA Power Networks – Determination 2015 – 2020, Overview, p. 54, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/final-decision

[92] AER, March 2018, Preliminary framework and approach, SA Power Networks regulatory control period commencing 1 July 2020, pp. 31 – 32, https://www.aer.gov.au/system/files/AER%20-%20SA%20Power%20Networks%20-%20Preliminary%20FA%20-%20March%202018.pdf

[93] Electricity Distribution Code 12.1, section 2.3.1(c)

4 Customer service standards

This section addresses the third of the reliability standard framework's four main elements: customer service standards and targets. Customer service is important because its quality influences how customers experience power outages, and because SA Power Networks relies on information from customers to identify and locate outages.[94]

Customer service measures currently relate to SA Power Networks' responsiveness to telephone and written enquires. However, SA Power Networks also communicates with its customers by email, through its website, Power@MyPlace app, SMS messages, social media (currently Facebook and Twitter) and other media (print, radio and online).

In its 2014 final decision on customer service standards for 2015 – 2020, the Commission noted that as 'customers become more reliant on other communications channels to report supply interruptions, the current focus on telephone responsiveness may need to be revisited'. [95]

Although telephone communication remains vital to SA Power Networks' business, use of other channels, and customer reliance on other channels, has escalated since 2014.

4.1 Telephone responsiveness standard updated

The draft decision is to retain the telephone responsiveness standard, with an updated definition.

SA Power Networks is currently obliged to use its best endeavours to respond to 85 percent of telephone calls within 30 seconds. This target applies to average annual performance, in normal operations.

The Commission's draft decision is to update the definition of **responding to telephone calls** to be:

a) answering a customer's telephone call in person. Where a caller to an Interactive Voice Response (IVR) system is seeking to talk to an operator, then monitoring of the call waiting time should commence when the caller selects the relevant operator option and cover the resulting time up and until an operator picks up the call, to deal with the caller's issue; and

b) answering a customer's telephone call by providing access to a computer/telephony based interactive service which is able to process calls by providing information or directing calls to a service officer.

4.1.1 Rationale

Telephone contact continues to be important for customers. Though contact through other channels has increased, the number of telephone calls has not dropped. In the five years to 2016-17 SA Power Networks received an average of 558,000 calls per year.

The current standard focuses on SA Power Networks' responsiveness to the calls received, so it is important that the time customers are required to wait is accurately captured. A call is only considered to be 'answered' when the customer has been able to start to resolve their query, whether that is through talking with a person or through automated self-service options.

[94] Equivalent customer service standards for National Energy Retail Law retailers was transferred to the Australian Energy Regulator with the commencement of the National Energy Customer Framework, but responsibility for administering SA Power Networks' customer service standards and targets remains a jurisdictional requirement.

[95] Essential Services Commission of South Australia, 2014, SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period, Final Decision, p. 20.

The current Code definition of 'responding to telephone calls' is potentially ambiguous about whether the time a customer spends waiting after the automated call answering system directs their call to a person counts towards the 30 second target.

The Code currently defines **responding to telephone calls** as:

> a) answering a customer's telephone call in person; and
>
> b) answering a customer's telephone call by providing access to a computer/telephony based interactive service which is able to process calls by providing information or directing calls to a service officer.
>
> but does not include the answering of a call by being placed in an automated queue to wait for one of the options above.[96]

Electricity Guideline No. 1 further clarifies the Commission's expectation on responding to telephone calls:

> 'Where an IVR operates, it is not appropriate to regard the call as being answered unless the customer has selected an automated response option and does not seek to talk to an operator (note: a call is not considered to be answered by being placed in an automated queue).
>
> Where a caller to an IVR system is seeking to talk to an operator, then monitoring of the call waiting time should commence when the caller selects the relevant operator option and cover the resulting time up and until an operator picks up the call, to deal with the caller's issue.'[97]

However, this intention is not clear in reading the Code's definition in isolation. To address the potential ambiguity, the draft decision is to amend the current definition to include the clarification currently included in Electricity Guideline No. 1.

4.2 Written responsiveness standard retained

The draft decision is to retain the written responsiveness standard for letter and fax, and email.

SA Power Networks is currently obliged to use its best endeavours to respond to 95 percent of written enquiries (by email, fax or letter) within five business days. This target applies to average annual performance, in normal operations.

4.2.1 Rationale

Written enquiries by email, fax or letter account for less than one percent of customer contact with SA Power Networks. Despite representing a small proportion of contact, timely response to written enquires remains important.

This Review considered whether to establish a different responsiveness standard for email, as written enquires by email can be responded to quickly, and customers expect a quick response.

However, genuinely considering and resolving each enquiry requires thought, so the existing timeframe of five days for a fuller response is reasonable. The Commission expects SA Power Networks will

[96] Electricity Distribution Code 12.1, section 2.1.2

[97] ESCOSA, July 2015, Electricity Regulatory Information Requirements – Distribution, Electricity Industry Guideline No. 1 (G1/12), p. 15, see https://www.escosa.sa.gov.au/ArticleDocuments/512/20141007-Elec-GuidelineNo1-EG12.pdf.aspx?Embed=Y

acknowledge customer emails quickly (eg, straight away, by automated response), as part of its normal business practice.

The definition of response to written enquiries will remain the same: direct or telephone or written response in which the distributor either answers the enquiry or acknowledges receipt of the enquiry and indicates the process and timetable to be followed in dealing with the enquiry.[98]

4.3 SMS communication standard introduced

The draft decision is to require that when SA Power Networks provides information about outages by SMS, it must be timely, current and accurate.

Specifically, SA Power Networks must SMS registered customers as soon as possible to:

- advise it is aware of an outage
- advise of the outage cause
- provide an estimated restoration time, and
- provide updates, as required, until power is restored.

There is currently no communication measure specifically for SMS.

4.3.1 Rationale

SMS is an increasingly important communication channel, and it is important that information provided by SMS is timely, current and accurate. Accuracy of restoration information provided to customers by SMS was of particular concern with regards to the 27-28 December 2016 storms, and was investigated as part of the Commission's 2017 Distribution Licence Compliance Review.[99] That review reported a series of actions to improve accuracy of information sent by SMS, which SA Power Networks has since pursued.

This proposal does not require SA Power Networks to provide an SMS service, as it is already providing this service, without regulation. Further, it does not set a timeframe for sending SMS messages, as current practice is to message as soon as possible – typically within around 10 -15 minutes of becoming aware of an outage.

Currently, SA Power Networks only has phone numbers and consent to send messages about outages to around 40 percent of its customers. This proposal does not require SA Power Networks to meet targets for increasing this number, as it is already doing so proactively.

4.4 Communication quality measure: for monitoring

The draft decision is to require SA Power Networks to monitor and report on a communications quality measure, as agreed with the Commission.

Initially, this will be the Customer Service Benchmarking Australia customer service measure and its sub-measures (for planned and unplanned interruptions, new connections and complaints). There is no current standard or performance target for communication quality.

[98] Electricity Distribution Code 12.1, section 2.1.5

[99] Essential Services Commission of South Australia, June 2017, Distribution Licence Compliance Review of SA Power Networks in relation to the 27-28 December 2016 severe weather event, p. 26.

4.4.1 Rationale

Responsiveness is only one element of customer service, and responsiveness measures (timeframes for answering enquiries) do not capture communication quality.

Communication quality measures cut across communication channels, and can capture use of hard to measure channels like social media. This Review has considered standards for social media and Internet communication. Developing measures for these channels that are robust, and will endure over time, is challenging. For example, while SA Power Networks tracks the inbuilt customer responsiveness and satisfaction measures on Facebook and Twitter, commonly used social media platforms are likely to change over time, making them unsuitable to include in the reliability standards framework.

Communication quality measures already exist. For example, the economic regulator of the water sector in England and Wales (Ofwat) uses a composite measure as the basis of its service incentive mechanism.[100]

In Australia, the composite measure developed by Customer Service Benchmarking Australia is being increasing adopted by electricity distributors and water utilities.[101] This measure captures satisfaction and ease of overall experience in four areas (planned and unplanned interruptions, new connections and complaints), and as an aggregate score. It allows comparison over time, and benchmarking against interstate utilities.

SA Power Networks has recently engaged Customer Service Benchmarking Australia to measure its communication quality using this composite measure.

[100] Ofwat, 2018, Customer service incentive mechanism, https://www.ofwat.gov.uk/regulated-companies/company-obligations/customer-service/

[101] AusNet Services, TasNetworks and the Australian Gas Infrastructure Group also use this tool.

5 Performance monitoring and reporting

This section addresses the fourth of the reliability standard framework's main elements: performance monitoring and reporting.

Performance monitoring and reporting promotes transparency. It informs customers about the level of service they are receiving (at an aggregate level) and identifies reasons for poor performance. It provides an incentive for improvement. It also provides data required to develop reliability standards, assess compliance, and inform the decision making processes of regulatory agencies, regulated businesses and government.

Currently, the Commission has a standing 'data request' of SA Power Networks, in the form of Electricity Industry Guideline No. 1.[102] The Commission makes additional information requests as required (eg regarding significant performance reporting, or to make best endeavours assessments when performance targets are not met).

Information submitted by SA Power Networks currently forms the basis of a series of reports, published by the Commission, on SA Power Networks' performance. These are:

- Quarterly operational and performance reports. These brief reports provide an indication of customer service and reliability performance in relation to annual targets, and of GSL payments.
- Annual regulatory performance reports. These more detailed reports describe longer-term trends in customer service, reliability performance and GSL payments. They discuss in detail performance issues and the impact of severe weather events.
- Significant performance event reports. These reports describe performance relating to significant events, such as an event that causes extended outages for a large number of customers. In 2017, the Commission published a significant performance event report in relation to the 28 September 2016 and 27-28 December 2016 outages.[103,104]

This draft decision proposes several changes to current performance monitoring and reporting arrangements.

5.1 SA Power Networks will report directly to its customers

The draft decision is that SA Power Networks will report directly to its customers on all matters currently captured in performance reporting.

This will include all data and matters set out in Electricity Guideline No. 1. The Commission expects, at a minimum, quarterly and annual reporting, and reports following significant performance events.

This is in addition to SA Power Networks publishing an annual MECS (see section 2.5), which will form the basis for reporting following performance target exceedances or significant performance events.

[102] Essential Services Commission of South Australia, 2017, Electricity regulatory information requirements – Distribution, Electricity Industry Guideline No. 1, http://www.escosa.sa.gov.au/ArticleDocuments/512/20141007-Elec-GuidelineNo1-EG12.pdf.aspx?Embed=Y

[103] Essential Services Commission of South Australia, 2017, SA Power Networks Distribution Compliance Review, http://www.escosa.sa.gov.au/ArticleDocuments/1054/20170623-Electricity-SevereWeatherEvent27-28Dec2016-DistributionLicenceComplianceReview-SAPN.pdf.aspx?Embed=Y

[104] Historically, the Commission reported on summer performance each year from 2006-07 to 2009-10 (as 'Summer distribution network performance reports').

Direct public reporting should improve accountability of SA Power Networks to its customers. This change will also encourage reporting to be integrated with SA Power Networks' ongoing customer communications and engagement program.

With SA Power Networks reporting directly to the public, the Commission will not invest any less effort in performance monitoring. It will continue to scrutinise the performance of SA Power Networks, and redirect effort from preparing reports to auditing, data assurance and analysis.

5.2 Annual regional 'report cards'

The draft decision is that SA Power Networks will include, in its annual performance reporting, a set of regional 'report cards'.

This will be in addition to reporting against standards and targets (established for the ten region-based categories described earlier in this draft decision). Report cards will be prepared for each of the region-based categories, in a manner that is accessible for customers.

Report cards must include performance of relevant major regional centres. They would detail performance in rural and urban parts of each region, major outages, key issues, and upcoming projects. They must include data on normalised and non-normalised unplanned interruptions, shown against average historical performance, and explain departures from that longer-term performance.

This measure responds to requests from stakeholders (eg Business SA) for information about reliability performance at a granular level. This may be integrated into SA Power Networks' broader communications and engagement strategy, and is consistent with other elements in this draft decision.

5.3 Reporting on low reliability feeders

The draft decision is that SA Power Networks will continue to report on the performance of low reliability feeders, which will be defined with respect to regional performance targets.

Currently, a low reliability feeder is defined as an individual feeder with USAIDI performance approximately twice as high as the USAIDI target for that feeder class for two consecutive financial years. The elements of performance reported are:

- USAIDI and USAIFI performance as at 30 June;
- normalised USAIDI and USAIFI as at 30 June;
- geographic location of the feeder; and
- action already undertaken and/or any planned future action to improve the reliability of each identified feeder.

For the 2020 – 2025 period, the draft decision is that SA Power Networks will continue that reporting, but that the definition of low reliability feeder will be adjusted to be: an individual feeder with USAIDI performance approximately twice as high as the USAIDI target for that region for two consecutive financial years.

Continued reporting on low reliability feeders is important because separate network performance standards or targets for customers who experience reliability that is far below average is not proposed.

Monitoring low reliability feeders allows for identification of customers not benefiting from (or receiving performance consistent with) average reliability standards and targets for an extended period of time. Adjusting the definition to identify low reliability feeders relative to region-based categories is consistent with other elements of this draft decision.

5.4 Electricity Guideline No. 1 will be revised

Electricity Guideline No. 1 will be revised to reflect the Commission's decision on reliability standards for 2020 – 2025.

Electricity Guideline No. 1 will continue to require reporting on customer service, reliability of supply, the GSL scheme, statistical information, embedded generation, and requirements of the South Australian Government's Office of the Technical Regulator. It will be revised to reflect the Commission's final decision on reliability standards for 2020 – 2025.

5.5 SA Power Networks must publish time-series data

SA Power Networks will be required to publish time-series data (from 2005-06 onwards) that is consistent with the overall revised framework.

SA Power Networks will be required to publish time-series data (from 2005-06 onwards) based on the Commission's decision on reliability standards for 2020 – 2025. This will provide the basis for comparison against historical performance.

Whereas currently the Commission publishes a time-series dataset on its website, from 1 July 2020 SA Power Networks will be required to publish this information directly.

6 Other matters: microgrids and off-grid supply

Submissions to this Review's Objectives and Process paper asked the Commission to have regard to increasing amounts of distributed energy resources, both generation and storage. Specifically, submissions asked the Commission to establish a reliability target for microgrids, and address SA Power Networks' role in facilitating distributed energy resources.[105]

A microgrid is 'a power system that supplies electricity to multiple consumers but is not physically connected to the national electricity system'. Off-grid supply through microgrids as an alternative to grid-connected supply may offer benefits including: lower distribution costs, investment flexibility, improved safety, and improved reliability.[106]

Currently, the National Electricity Rules do not allow SA Power Networks to provide off-grid supply through microgrids or individual power systems, as they are not regulated distribution services.[107]

However, the AEMC recently decided favourably on the principle of allowing off-grid supply to be considered a distribution service for customers who already have a grid connection, for whom off-grid supply would cost less than maintaining that connection, and where competition is not practical.[108] The AEMC is now developing the law and rule changes required to make this change.

The Commission will consider whether changes to jurisdictional reliability standards are required to support those changes, if and when they are implemented. However, it is noted that while off-grid supply would be challenging to relate to the Code's current performance standards based on feeder-type categories, it would relate simply to standards based on region-based categories.

[105] AGL, Clean Energy Council, and S&C Electric submissions

[106] AEMC 2017, National Electricity Amendment (Alternatives to grid-supplied network services) Rule 2017 pp. 15-18, see https://www.aemc.gov.au/Rule-Changes/Alternatives-to-grid-supplied-network-services

[107] The AEMC found off-grid supply unlikely to constitute a distribution (or transmission) service, so it to be unlikely that a distributor would be permitted to provide it, though an affiliate or subsidiary of the distributor could do so.

[108] AEMC 2017, National Electricity Amendment (Alternatives to grid-supplied network services) Rule 2017, see https://www.aemc.gov.au/Rule-Changes/Alternatives-to-grid-supplied-network-services

7 Next steps

The Commission seeks stakeholder views on this draft decision by 14 September 2018. The inside cover of this report explains how to make a submission.

The Commission would also be pleased to meet informally with stakeholders, either individually or with representative organisations, to discuss the draft decision. If you or your organisation wish to meet with Commission staff, please use the contact details on the inside cover of this inquiry Draft Report.

The Commission aims publish its final decision on reliability standards to apply to SA Power Networks from 1 July 2020 in December 2018.

Appendix 1: Network reliability performance since 1999

The Commission is required to impose minimum standards of service that are at least equivalent to the levels that existed during the year prior to 11 October 1999. According to the Electricity Act 1996 section 23 (1)(n)(v), the distribution licence issued by the Commission to SA Power Networks must require:

> '… the electricity entity to comply with code provisions as in force from time to time (which the Commission must make under the *Essential Services Commission Act 2002)* imposing minimum standards of service for customers that are at least equivalent to the actual levels of service for such customers prevailing during the year prior to commencement of this section and take into account relevant national benchmarks developed from time to time and requiring the entity to monitor and report on levels of compliance with those minimum standards'.

Commencement of this section was through the Electricity (Miscellaneous) Amendment Act 1999, proclaimed on 30 September 1999 with provisions taking affect from 11 October 1999.[109,110]

Due to issues with data quality, the Commission considers standards of service prevailing in 2005-06 as a proxy for the standards of service that existed during the year prior to 11 October 1999. The Commission routinely uses 2005-06 as the base year for analysing SA Power Networks' long-term reliability performance, against which current performance is comparable.

Levels of service prevailing in 2005-06 are set out in Table 6, for the whole network, each feeder-type category and each reporting region.

Table 6: Baseline performance data: standards of service prevailing in 2005-06

Region	USAIDI	Normalised USAIDI	USAIFI	Normalised USAIFI
Network-wide	200	185	1.95	1.83
Feeder-type categories				
CBD feeders	28	28	0.25	0.25
Urban feeders	160	147	1.72	1.66
Short rural feeders	208	187	2.19	2.01
Long rural feeders	358	335	2.52	2.42
Reporting regions				
Adelaide Business Area	28	28	0.25	0.25
Major Metropolitan Areas	161	148	1.72	1.66
Central Region	223	213	1.60	1.54
Eastern Hills and Fleurieu Peninsula	285	249	3.33	2.97
South East	206	206	2.12	2.12
Upper North and Eyre Peninsula	555	533	3.19	3.03
Kangaroo Island	1076	758	8.23	7.43

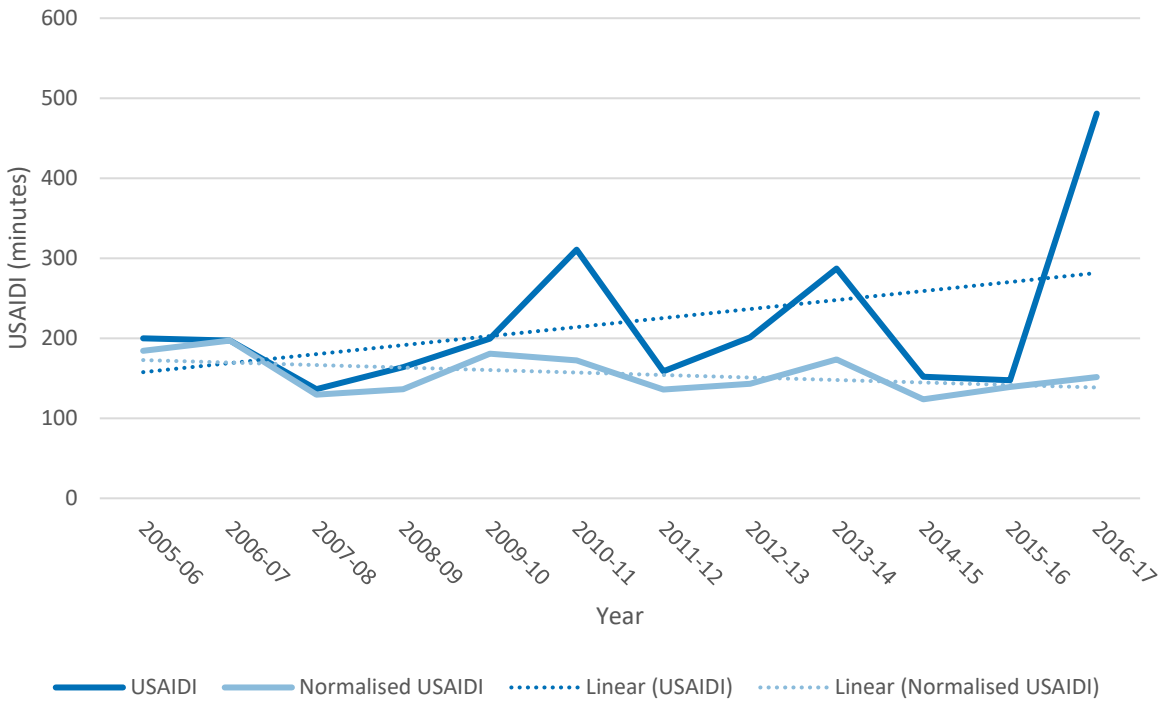
Source: SA Power Networks, data prepared for SA Power Networks Annual Reliability Performance Report for 2016-17

[109] Section 23 of the Electricity (Miscellaneous) Amendment Act 1999
[110] South Australian Government Gazette No. 139, 30 September 1999, p. 1341

Since 2005-06, network-wide normalised USAIDI, which excludes MEDs, has improved. The Commission has set network performance standards for normalised reliability since 2015. The Electricity Act provisions are not limited to normalised reliability.

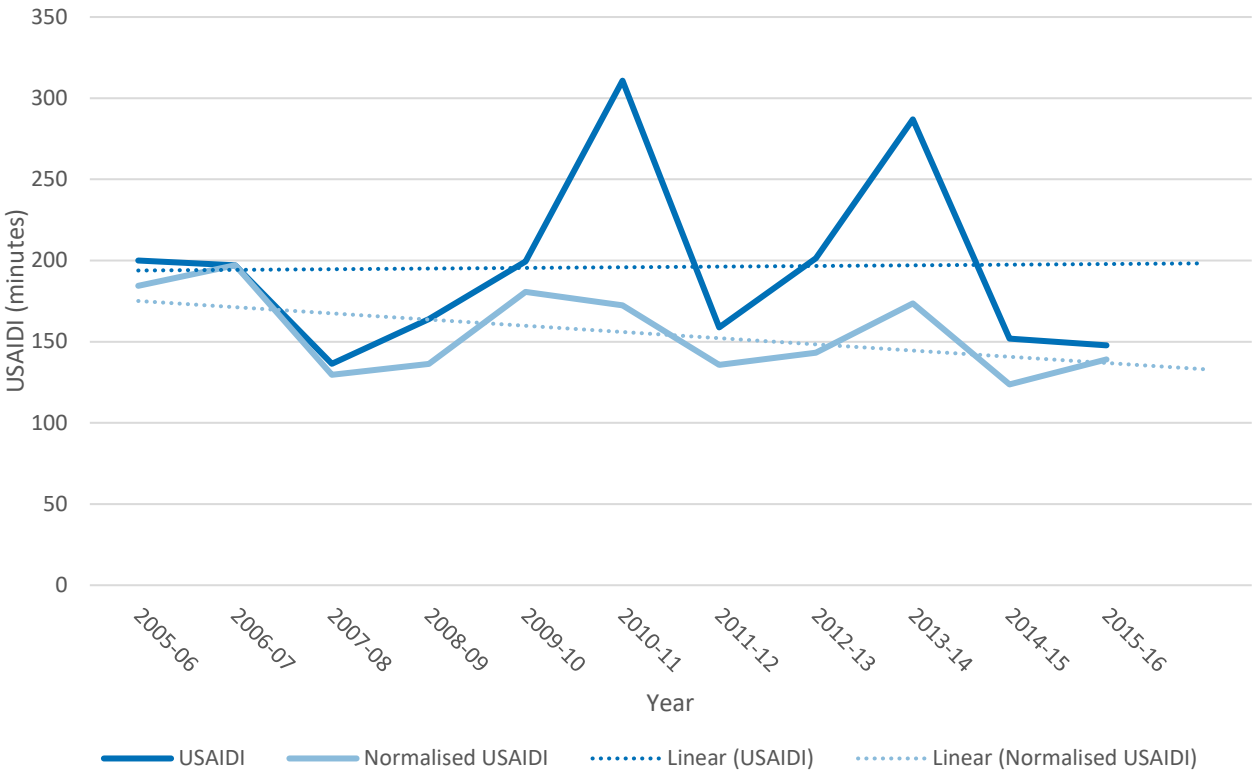
Non-normalised USAIDI exhibits high variability, most notably in 2016-17, a year with an unusual number of MEDs (see Figure 5). The trend, excluding 2016-17, is that extremes in variability offset each other (see Figure 6). Trends in normalised and non-normalised USAIFI are shown in Figure 7.

Figure 5: Overall and normalised USAIDI performance since 2005-06



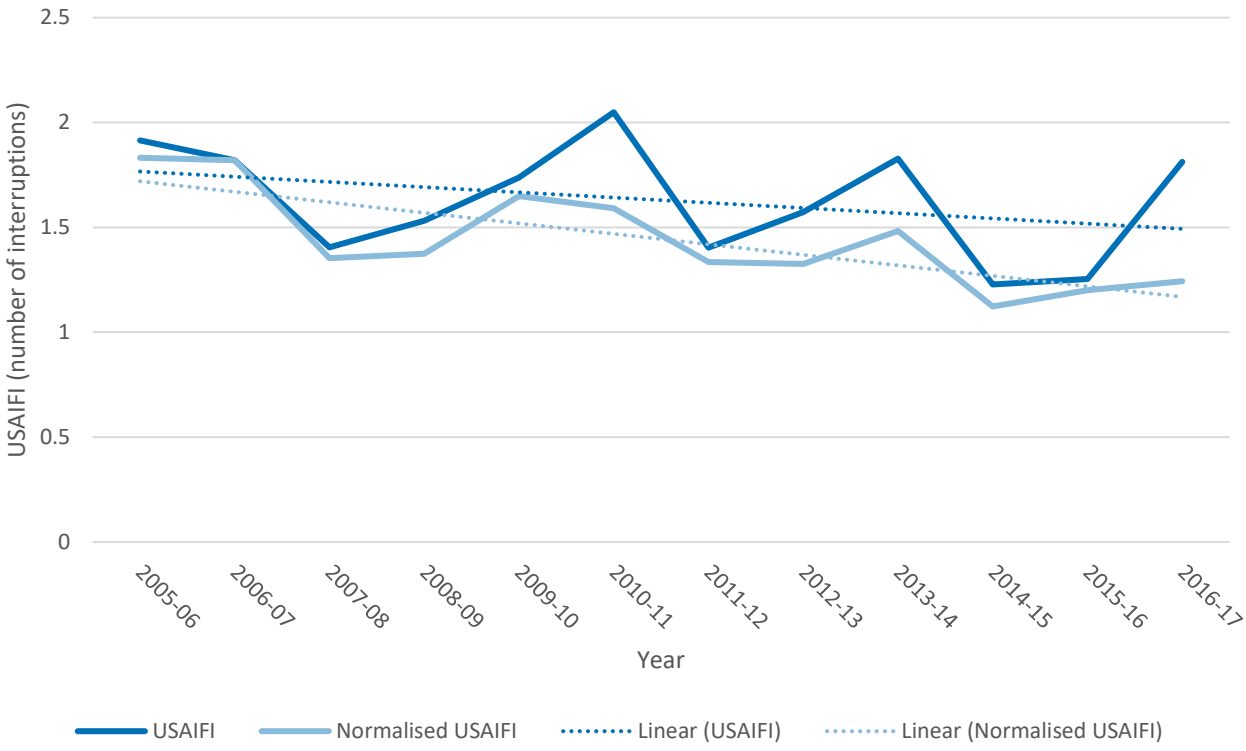
Data source: SA Power Networks, Annual Performance Reporting to Commission

Figure 6: Overall and normalised USAIDI performance since 2005-06, excluding 2016-17



Data source: SA Power Networks, Annual Performance Reporting to Commission

Figure 7: Overall and normalised USAIFI performance since 2005-06



Data source: SA Power Networks, Annual Performance Reporting to Commission

Appendix 2: Cost-value scenarios

The cost-value scenarios are based on using capital expenditure to reduce interruption frequency on high voltage feeders. SA Power Networks maintains a database of costed capital expenditure projects.

Inclusion of options based on using operating expenditure to improve reliability (eg by increasing the number of depots and crews) was investigated. However, projects and costs held by SA Power Networks were not developed enough to provide a basis for, or to complement, scenarios based on capital expenditure.

The Commission requested that SA Power Networks identify the least cost solution for each level of reliability improvement. Therefore, the combination of capital expenditure projects used to achieve each scenario are different. Projects include:

- Vegetation: removing vegetation, covering overhead conductors, undergrounding.
- Lightning: insulator upgrades and surge protection.
- Animal guards: installing animal guards.
- Reducing the number of customers interrupted by a fault: by installing mid-line reclosers, or through feeder automation.
- Reducing restoration times: by installing remote monitoring and control on switches, or using line fault indicators.

In metropolitan scenarios, the main projects used to deliver improvements are vegetation management, animal guards, feeder automation, and remote monitoring and control of switches. In non-metropolitan scenarios, the main projects used are insulator and surge protection upgrades, mid-line reclosers, switch upgrades, remote monitoring and control of switches and line fault indicators.

There is a high level of confidence in costs for some scenarios (eg most of those based on one percent USAIFI improvements), where costs are drawn directly from SA Power Networks' costed capital expenditure database.

There is a lower level of confidence in costs for other scenarios (eg those based on five and ten percent USAIFI), where costs from the database have been escalated. The confidence level (error margins) associated with the costs for each scenario are included in Table 7 and Table 8.

The error margins have an important influence on projected costs. For example, an error margin of zero percent indicates a high level of certainty. The projected cost for a five percent improvement for low reliability feeders, with an error margin of zero percent, is $2.02 million. The cost range of a five percent improvement for non-metropolitan customers, with an error margin of 50 percent, is $99.5 - $149.5 million. The cost range of a five percent improvement for metropolitan customers, with an error margin of 100 percent, is $133.7 - $267.4 million.

Table 7: Reliability scenarios for metropolitan, non-metropolitan customers, and low reliability feeder customers

Scenario		Metropolitan	Non-metropolitan	Low reliability feeders
Customers		624,851	261,689	27,084
Electricity consumption (MWh, 2016-17)		6,940,449	2,777,118	166,235
Mean performance (five years 2010 - 2015)	USAIDI	120	275	313
	USAIFI	1.35	2.40	2.81
1% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.01	0.02	0.03
	USAIDI	1.1	3.0	14.9
	Cost ($M)	8.25	10.57	2.02
	Error margin	0%	0%	0%
5% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.07	0.12	0.14
	USAIDI	4.9	21.3	47.2
	Cost ($M)	133.7	99.5	10.1
	Error margin	100%	50%	0%
10% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.14	0.24	0.28
	USAIDI	9.6	49.5	93.0
	Cost ($M)	368.9	281.3	30.3
	Error margin	200%	100%	100%

Notes:

1. Metropolitan areas includes metropolitan Adelaide, and some feeders in Port Lincoln, Whyalla, Port Augusta, Mount Gambier and Port Pirie. It does not include the Adelaide CBD.
2. Low reliability feeders are spread across metropolitan and non-metropolitan areas. They are not excluded from the metropolitan and non-metropolitan groups.
3. SA Power Networks provided error margins as escalation rules (ie multipliers to apply to actual costs). For example, where 0-25 percent of project cost was based on actuals, a further 200 percent was added to produce the estimated cost.
4. Values used for the contingent valuation survey and VCR analysis differ very slightly. SA Power Networks first provided this information in March 2018. This was used for the contingent valuation survey. It provided updated estimates in May 2018. These were used for the VCR analysis.
5. The total number of customers represented across metropolitan and non-metropolitan areas is 886,500. This is based on the number of meters (National Meter Identifiers) active over a year, and is slightly more than the number of meters active at any one point in time.

Table 8: Reliability scenarios disaggregated by region

Scenario		Barossa, Mid-North, Yorke Peninsula	Eyre Peninsula	Fleurieu Peninsula	Adelaide Metropolitan Area	Eastern Hills	Riverlands and Murraylands	Rural Metropolitan Centres	South East	Upper North
Customers		57,724	15,969	45,309	583,352	37,210	48,162	41,499	32,252	25,063
Electricity consumption (MWh, 2016-17)		596,040	113,502	270,762	6,513,311	382,839	650,238	427,138	424,197	339,539
Mean performance (five years 2010 - 2015)	USAIDI	200	425	200	115	350	185	85	235	300
	USAIFI	1.50	1.85	1.65	1.25	2.55	1.35	0.85	1.75	1.35
1% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.02	0.02	0.02	0.01	0.03	0.01	0.01	0.02	0.01
	USAIDI	3.3	6.8	5.1	1.0	9.8	6.0	3.8	4.3	3.4
	Cost ($M)	1.74	0.65	2.24	6.07	3.13	1.81	2.57	0.11	0.76
	Error margin	0%	0%	100%	0%	0%	10%	0%	0%	0%
5% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.08	0.09	0.08	0.06	0.13	0.07	0.04	0.09	0.07
	USAIDI	12.8	36.7	25.4	4.4	26.7	26.2	6.8	19.7	24.1
	Cost ($M)	7.81	4.85	15.68	117.99	14.36	16.67	4.54	8.20	6.57
	Error margin	5%	5%	200%	100%	0%	100%	0%	100%	5%
10% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.15	0.19	0.17	0.13	0.26	0.14	0.09	0.18	0.14
	USAIDI	24.6	74.0	50.8	8.6	47.8	51.4	10.4	38.9	50.0
	Cost ($M)	18.65	12.34	32.47	327.83	35.43	44.54	8.23	23.36	20.41
	Error margin	50%	50%	200%	200%	50%	200%	50%	200%	100%

Notes:

1. Adelaide Metropolitan Area does not include the CBD.
2. Rural Metropolitan Centres based on feeders in Port Lincoln, Whyalla, Port Augusta, Mount Gambier and Port Pirie.
3. SA Power Networks provided error margins as escalation rules (ie multipliers to apply to actual costs). For example, where 0-25 percent of project cost was based on actuals, a further 200 percent was added to produce the estimated cost.
4. Values used for the contingent valuation survey and VCR analysis differ very slightly. SA Power Networks first provided this information in March 2018. This was used for the contingent valuation survey. It provided updated estimates in May 2018. These were used for the VCR analysis.
5. Note that the total of costs here (Table 8), and in Table 7 are different. Segmenting the network in different ways means different levels of investment are required to achieve reliability improvements. That is, making a fixed level of improvements for each region has a cost different to the same improvement for the three groups in Table 7.
6. The number of customers is based on the number of meters (National Meter Identifiers) active over a year, and is slightly more than the number of meters active at any one point in time.

Appendix 3: Economic assessment of cost-value scenarios

This Review used two complementary methods for quantifying benefits: contingent valuation and desktop VCR analysis. Desktop analysis using VCR is widely used for decision making in the electricity sector. However, it has limitations including:

- Those inherent in the methods and design originally applied by AEMO (a combination of contingent valuation and choice modelling), which include a wide confidence interval of +/- 30 percent.[111]
- Those acknowledged by AEMO in its application guide (including that VCRs should not be used to assess high impact or prolonged widespread outages).[112]
- A single, uniform value of customer reliability is an average. In reality, the value of reliability varies across customer groups (eg business, industry, agriculture, residential), and across individual customers.
- Adjustments based on Consumer Price Index and economic structure do not account for underlying changes in how customers value reliability that have occurred since 2013-14. [113]

The contingent valuation study commissioned for this Review addresses some of these weaknesses: it is a contemporary valuation, based on the preferences of South Australian customers; it puts forward improvement scenarios based on real projects; and provides insights into how willingness to pay varies across customer groups (including by showing the amount of customers not willing to pay anything at all for reliability improvements).

However, contingent valuation also has limitations including the possibility of starting point bias, its ability to capture how people prioritise options for expenditure, the difference between stated willingness to pay and how people might behave in a 'real' market, and the extent to which responses are influenced by income (ability to pay). The approach and results of each method are summarised below.

Contingent valuation analysis

The Commission engaged consultants Oakley Greenwood and Wallis Market Research to complete a cost-value assessment using contingent valuation to quantify the benefits of reliability improvements. A final project report accompanies this draft decision.

Why use contingent valuation?

Contingent valuation is an economic valuation technique for quantifying the value of non-market goods or services, such as reliability improvements, for input into economic assessment. It uses surveys to ask people how much they are willing to pay for a benefit. It has been used in the electricity industry to ask people about their willingness to pay for reliability improvements. For example, it was one technique used by AEMO to develop its VCRs.[114]

In selecting the contingent valuation method, use of another non-market valuation technique, choice modelling, was considered. Choice modelling asks people about their preferences for different

[111] AEMO 2014, Value of Customer Reliability Final Report, p. 31
[112] AEMO 2014, Value of Customer Reliability Application Guide p. 29
[113] AEMO recognises such an approach will likely result in step changes when survey results are updated, but does not recommend a model to limit this step change.
[114] AEMO 2014, Value of Customer Reliability review project page. Includes links to Final Report and Application Guide: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review

'packages' of non-market goods or services, such as unplanned interruptions with different characteristics (duration or frequency, time of year, time of day). It uses survey responses to model the value of those goods or services. It has also been used in the electricity industry: AEMO combined choice modelling with contingent valuation to construct its VCRs.

Contingent valuation was selected for this project because:

- It was the most direct way to obtain value estimates, in absolute dollar terms, and construct demand curves for reliability improvements.

  The contingent valuation survey presented people with starting values based on real costs of making reliability improvements, and asked if they were willing to pay. If the amount based on the real cost was accepted, people were asked if they would pay a little more. If rejected, people were asked if they would pay a little less, and so on. This allowed demand curves to be constructed for each improvement scenario, which show the range of amounts people are willing to pay.

- The reliability improvement scenarios developed for this Review have limited 'dimensions': outage frequency (which has a known impact on outage duration), customer group (metropolitan, non-metropolitan or low reliability feeder), and GSL (duration) payments.

- It was possible to adapt the contingent valuation method to ascertain respondent's priorities for different options (ie the 'dimensions' set out in the above point), by adding a reconciliation section, where respondents were able to review and prioritise their answers.[115]

The rationale for using contingent valuation is further described in section 2.2.2 of the Oakley Greenwood Final Report.

As all customers share the cost of distribution services regardless of whether they benefit directly, the contingent valuation survey used in this Review asked customers about willingness to pay to improve their own reliability, and about willingness to subsidise improvements for customers in other areas. These responses were combined to quantify total willingness to pay.

How were costs presented to customers?

As noted above, the contingent valuation survey presented people with starting values based on real costs of making reliability improvements. A consideration in deciding how to present these costs to customers was whether to:

a) Present the **bill increase** that would be required to deliver that improvement (ie the cost smeared across all SA Power Networks customers). For example, $30 million expenditure for low reliability feeders smeared across all customers equates to an ongoing annual bill increase of $2 for a typical residential customer and, on average, $5 for a business customer. Or,

b) Present the **full costs** firstly to those customers who would benefit directly from improvements, and then, separately, to those who would be required to subsidise improvements.

[115] There have been recent developments in using contingent valuation as an alternative to choice modelling by including a reconciliation section. A recent Australian study about creek rehabilitation provides an example (Bennett, J. J. Cheesman and K. Milenkovic, 2017, Prioritising environmental management investments using the Contingent Valuation Method, Journal of Environmental Economics and Policy). The study examined creek rehabilitation funded through rates bills. It asked people about their willingness-to-pay for several activities, then summarised their responses. People were invited to alter the individual amounts in the context of their total budget. This allowed people to assess trade-offs within their overall willingness to pay, and so reassess their prioritisation of spending.

In this approach, $30 million expenditure for low reliability feeders smeared across low reliability feeder customers (27,000) equates to an ongoing annual cost of $55 for a typical residential customer and, on average, $110 for a business customer.

On the advice of Oakley Greenwood, option b) was selected. [116] For each reliability improvement scenario, full costs were presented firstly to customers who would benefit directly and then to those who would not. The rationale is that the starting point based on full costs is more likely to ascertain whether the cost of real alternatives is acceptable. This is further explained in the accompanying Oakley Greenwood Final Report (sections 2.4 and 3.4).

How were benefits presented to customers?

The cost-value scenarios are based on reducing interruption frequency (USAIFI) by one, five and 10 percent. Interruption frequency was chosen as the basis for the scenarios because it can be impacted directly and predictably by capital investment.

When interruption frequency (USAIFI) is reduced, interruption duration (USAIDI) also falls. In the contingent valuation survey, reliability benefits were presented to customers as reductions in average annual interruption duration (USAIDI).

In the survey, short statements on current reliability introduced each section. For example: 'On average, customers like you in metropolitan Adelaide and major regional centres experience one unplanned power outage and just under two hours without power each year.'

The survey then asked how much each customer would be willing to pay for improvements. For example: 'The Essential Services Commission could set standards to reduce the average length and number of unplanned outages. The standard could be changed to reduce the two-hour average length of time customers like you are without power by five minutes. Would you be willing to pay $10 more each year – about $2.50 on each quarterly bill – for that improvement?'.

Sample structure and confidence levels

The contingent valuation study was conducted in May 2018 and obtained responses from 1,313 customers (1000 residential and 313 business).

The sample was designed to provide valid results for: the State as a whole; metropolitan customers; non-metropolitan customers; and, low reliability feeder customers. Each of these segments was required to have a representative mix of residential and business customers.

The residential sample was representative in terms of income, age and gender. The business sample was representative in terms of business size (by annual electricity consumption).

Residential respondents were required to have full or partial responsibility for paying the household electricity bill; business respondents were asked if they were the person who 'is in the best position to make decisions regarding electricity bills and electricity supply.'

Achieved sample sizes, and associated confidence levels and margins of error are shown in Table 9. Full detail on the sample design is included in Appendix B of the accompanying Oakley Greenwood Final Report, and statistical reliability is addressed in Appendix D of that report.

[116] Oakley Greenwood 2018, Economic assessment of electricity distribution reliability standard packages, Final Report, p. 17.

Table 9: Statistical error bands of the achieved sample

Segment	Sample size	Assumed population size	Error band at 95 percent confidence level	Error band 90 percent confidence level
All residential	1,000	805,459	3.1%	2.6%
Residential – metro	504	550,594	4.4%	3.7%
Residential – non-metro	231	230,590	6.6%	5.5%
Residential – low reliability feeder	265	23,865	6.0%	5.0%
All business	313	108,575	5.6%	4.7%
Business – metro	160	54,257	7.7%	6.5%
Business – non-metro	85	31,099	10.6%	8.9%
Business – low reliability feeder	68	3,219	11.8%	9.9%

Source: Oakley Greenwood 2018, Economic assessment of electricity distribution reliability standard packages, Final Report, Appendix D.

Results

The results show only one reliability improvement scenario with a net benefit: an average 10 percent reduction in interruption frequency (associated with a 90 minute annual average reduction in outage duration) for the 27,000 customers on low reliability customers. This scenario has a net annual benefit of $1.9 million.

Results from all three 10 percent scenarios (for metropolitan customers, non-metropolitan customers, and low reliability feeder customers), as reported by Oakley Greenwood, are summarised below in Table 10. Benefits include the willingness to pay of customers who would benefit directly from reliability improvements (those on low reliability feeders), and the willingness of other customers to subsidise those improvements.

Table 10: Annual net benefit of reliability improvements based on an average 10 percent reduction in outage frequency

	Metropolitan customers	Non-metropolitan customers	Low reliability feeder customers
Benefit	$6,426,433	$8,506,401	$3,618,505
Cost	$19,953,578	$15,204,529	$1,655,154
Net Benefit (Cost)	($13,527,145)	($6,698,128)	$1,963,350

Note: 10 percent reductions in outage frequency are associated with 10 minute (metropolitan customers) 25 minute (non-metropolitan customers) and 90 minute (low reliability feeder customers) reductions in outage duration.

Results showed that not all customers are willing to pay for these improvements. Two-thirds of the 27,000 customers on low reliability feeders who would benefit directly from the improvements set out in Table 10 are not willing to pay anything at all for that improvement. This is consistent for both residential (62 percent) and business customers (66 percent).

Likewise, there are customers who would not benefit directly who do not want to subsidise improvements. Customers in metropolitan areas were not willing to subsidise improvements for low reliability feeder customers (54 percent of residential, and 52 percent of business), and nor did customers in non-metropolitan areas (38 percent of residential, and 52 percent of business).

Results from all three five percent scenarios (for metropolitan customers, non-metropolitan customers, and low reliability feeder customers), as reported by Oakley Greenwood, are summarised below in Table 11. None show a net benefit.

Table 11: Annual net benefit of reliability improvements based on an average five percent reduction in outage frequency

	Metropolitan customers	Non-metropolitan customers	Low reliability feeder customers
Benefit	$3,516,382	$4,779,454	$190,990
Cost	$7,231,752	$5,371,077	$562,536
Net Benefit (Cost)	($3,715,370)	($591,623)	($371,546)

Note: Five percent reductions in outage frequency are associated with five minute (metropolitan customers) 10 minute (non-metropolitan customers) and 45 minute (low reliability feeder customers) reductions in outage duration.

The contingent valuation study also quantified customer's willingness to pay for duration GSL payments. It found that 52 percent of customers are willing to pay for inconvenience payments, 42 percent are not willing to pay, and six percent do not know.

It found that, on average, customers want to pay less that they currently do for such a scheme. The survey explained this would 'mean the payments would be smaller, or fewer people would get them'.

In aggregate, customers are willing to pay $6.4 million per annum for duration GSL payments, described in the survey as 'inconvenience payments', for long outages (an average of $7 per year, per customer). This is less than customers currently pay, which is $10.1 million per year (an average of $12 per year, per customer), for the entire GSL scheme (97 percent of scheme costs are for duration payments). A full demand curve is included in the Oakley Greenwood Final Report as Figure 15.

VCR analysis

The second method used to quantify the benefits of each reliability improvement scenario was to apply an estimated, uniform, VCR across the cost-value scenarios of $40,620 per megawatt hour (MWh) of unserved energy. The estimated, uniform, VCR was established using values published by AEMO in 2014.

AEMO VCR estimates

The values published by AEMO in are based on results of customer surveys conducted in 2013-14. [117] These surveys sampled 3000 residential and business customers across Australia. A South Australian sub-sample was included. The main survey combined contingent valuation and choice modelling.

Contingent valuation was used to ask customers about their willingness to pay to avoid experiencing basic outages. This was used to establish a baseline VCR. Choice modelling was used to explore customer preferences for different outage types. Customers were shown a range of outage scenarios,

[117] AEMO 2014, Value of Customer Reliability review project page, see http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review

each with a set of attributes (eg length of outage, frequency of outage, time of day, week and year), and a fixed compensation amount. Customers were asked to choose between scenarios. Responses were used to adjust the baseline VCR.

The result of the AEMO survey and subsequent analysis was a suite of VCR values. It includes an aggregate VCR for the entire national electricity market, aggregate VCRs for each State, residential VCRs for each State, and business VCRs for each sector. AEMO considered developing residential VCRs for urban and regional customers in each State, but sample sizes were insufficient for statistically robust results.

Estimates based on the AEMO values are widely used by the AER and Australian electricity network service providers, and for determining STPIS incentive rates. [118] AEMO acknowledges the potential use of its VCR values in economic assessment to inform distribution network reliability standards. [119]

Estimated VCR

The estimated, uniform, VCR used in this Review is based on AEMO's aggregate VCR for South Australia, of $38.09 per kilowatt hour ($38,090 per MWh). [120] This VCR was adjusted for inflation for the period March 2014 to September 2017. A Consumer Price Index of five percent was used, a rate extracted from Australian Bureau of Statistics dataset 6401.0. [121]

Further, the AEMO VCR value was adjusted to reflect change in the composition of the South Australian economy since 2014. This was achieved using the Australian Energy Statistics published by the Department of Environment and Energy, and the ABS Energy Accounts. Values for 2016-17 were estimated by extrapolating available data.

Cost-value assessment model

A cost-value model was used to assess the net benefit of each reliability improvement scenario. This was achieved by applying the estimated uniform VCR to the reductions in interruption duration (USAIDI) associated with each scenario.

The model calculated net reliability benefits on an annual basis, as total annual reliability benefits less the total annual cost of improvements to deliver those benefits:

$$Net\ Reliability\ Benefit_{annual} = Reliability\ Benefit_{annual} - Cost_{annual}$$

Annual reliability benefits

The model calculated annual reliability benefits using the estimated, uniform VCR, avoided customer outage minutes (**Min**$_s$), and electricity consumption for the relevant network segment (***Consumption***$_{min}$):

$$Reliability\ Benefit_{annual} = (VCR) \times Min_s \times Consumption_{min}$$

Where:

[118] The VCR values used to derive the SA Power Networks STPIS rates are: $44,856 per MWh (CBD feeders) and $38,566 per MWh (urban, short rural and long rural feeders).These are based on AEMO 2014 values, escalated to the March 2015 quarter, see: AER, SA Power Networks Determination 2015-20, Attachment 11 – STPIS, page 11-8, see https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20SA%20Power%20Networks%20distribution%20determination%20-%20Attachment%2011%20-%20STPIS%20-%20October%202015.pdf

[119] AEMO 2014, Value of Customer Reliability Application Guide, p. 17, see http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf

[120] AEMO 2014, Value of Customer Reliability Final Report, p. 30, see http://www.aemo.com.au/-/media/Files/PDF/VCR-final-report--PDF-update-27-Nov-14.pdf

[121] As per the method indicated in AEMO 2014, Value of Customer Reliability Application Guide, see http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf

VCR is the estimated, uniform, value of customer reliability ($40,620 per MWh)

Min_s is the expected avoided customer outage minutes (avoided USAIDI) due to defined reliability improvements.

$Consumption_{min}$ is the estimated electricity consumption (MWh) per minute for the relevant network segment. This estimate was prepared by dividing annual electricity consumption as provided by SA Power Networks by the number of minutes in a year.

(Note that the product of Min_s and $Consumption_{min}$ gives the expected reduction in unserved energy).

Annual reliability costs

The model calculated annual costs as annual repayments of the capital expenditure over an assumed asset life, plus annual operating expenditure:

$$Cost_{annual} = Capex_{annualrepayment} + Opex_{annual}$$

Where:

$Opex_{annual}$ is applied as two percent of total capital expenditure.

$$\boldsymbol{Capex_{annualrepayment}} = \left(\frac{r}{1-(1+r)^{-n}}\right) Capex_{total}$$

Where:

r is an assumed discount rate (seven percent).

n is the assumed life cycle of the proposed capital expenditure (50 years).

$Capex_{total}$ is the total capital expenditure, as provided by SA Power Networks.

Sensitivity analysis

There is a +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR. This Review's VCR analysis incorporated a sensitivity analysis to assess the impact of the confidence interval on ranking of reliability improvement scenarios.

Low (-30 percent), base and high (+30 percent) estimates of VCR were calculated for each scenario. The full range of benefits was tested against costs, to consider if the preferred option changes.

For the purposes of assessing the impact of the +/- 30 per cent VCR confidence interval, costs were considered constant. In practice, the confidence interval associated with costs provided by SA Power Networks varied from zero to 200 percent (as shown in Table 7 and Table 8 in Appendix 2). This was considered separately, after analysis using the cost-value assessment model.

Results: metropolitan, non-metropolitan and low reliability customers

The VCR analysis found a net benefit in only one reliability improvement scenario: a one percent improvement in USAIFI for low reliability feeder customers (see Table 12). However, the sensitivity analysis showed that this positive net benefit is uncertain. It exists in two-thirds of cases representing variation in the +/- 30 percent confidence interval, meaning it is uncertain whether benefits offset costs.

Table 12 also shows there is no net benefit for one percent USAIFI reliability improvements for either metropolitan customers as a group, or non-metropolitan customers, as a group. The tables that follow show no net benefits for five or ten percent USAIFI reliability improvements.

Table 12: Net benefits of reliability improvement scenarios (one percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$590,021	$758,171	($168,150)
Non-metropolitan	$643,877	$980,074	($336,198)
Low reliability feeders	$191,423	$184,920	$6,504

Table 13: Net benefits of reliability improvement scenarios (five percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$2,628,274	$12,361,882	($9,733,608)
Non-metropolitan	$4,571,524	$9,199,755	($4,628,231)
Low reliability feeders	$606,388	$933,844	($327,457)

Table 14: Net benefits of reliability improvement scenarios (ten percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$5,149,272	$34,108,438	($28,959,166)
Non-metropolitan	$10,623,965	$26,008,956	($15,384,991)
Low reliability feeders	$1,194,789	$2,801,533	($1,606,744)

Results: ten region-based categories

Results for a one percent reduction in outage frequency across the ten region-based categories proposed in this draft decision are shown in Table 15.

Table 15: Net benefits of reliability improvement scenarios (one percent, regional disaggregation)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Barossa, Mid-North and Yorke Peninsula	$152,910	$160,875	($7,964)
Eyre Peninsula	$59,922	$60,346	($424)
Fleurieu Peninsula	$106,720	$207,069	($100,349)
Adelaide Metropolitan Area	$508,440	$561,201	($52,760)
Eastern Hills	$288,585	$289,390	($806)
Riverlands and Murraylands	$ 302,358	$167,489	$134,870

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Rural Metropolitan Centres	$126,309	$237,214	($110,904)
South East	$140,486	$10,477	$130,008
Upper North	$89,756	$70,050	$19,707

Results show small net benefits for this level of improvement for three regions: Riverlands and Murraylands ($134,870), South East ($130,008) and Upper North ($19,707).

For the Upper North, net benefits only exist in two-thirds of cases representing variation across the +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR, meaning it is uncertain whether benefits offset the costs.

For the Riverlands and Murraylands and South East, net benefits exist in all cases representing variation in the +/- 30 percent confidence interval. It is important to note the 10 percent confidence interval associated with costs for improvements in the Riverlands and Murraylands (though not for the South East), as per Table 8 in Appendix 2.

Results for five and ten percent reductions are not presented here in full, due to very limited net benefits. These are: at the five percent level, a net benefit exists only for the Upper North ($25,403), and in two-thirds of cases representing variation across the +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR. No net benefits exist at the ten percent level.

Appendix 4: Exclusions in draft revised STPIS

Table 16: Exclusions set out in the draft revised STPIS

Exclusion	Description
Transmission and generation failures	To adopt exclusion of transmission and generation failures as per items 3.3 (a) (2) – 3.3 (a) (6) of the draft revised STPIS. These include excluding interruptions due to: ▶ load shedding due to a generation shortfall ▶ automatic load shedding due to operation of under frequency relays following the occurrence of a power system under-frequency condition ▶ load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator ▶ load interruptions caused by a failure of the shared transmission network ▶ load interruptions caused by a failure of transmission connection assets except where interruptions were due to; (a) actions, or inactions, of the distributor that are inconsistent with good industry practice; or (b) inadequate planning of transmission connections and the distributor is responsible for transmission connection planning.
Electricity legislation	To adopt exclusion of emergencies as per item 3.3 (a) (7) of the draft revised STPIS. These are load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a distributor.
Emergencies	To adopt exclusion of emergencies as per item 3.3 (a) (8) of the draft revised STPIS. These are load interruptions caused by a direction from state or federal emergency services, provided that a fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction.
Interruptions less than three minutes	To replace exclusion of interruptions less than one minute.[122]
Other exclusions set out in the notes on standard definitions	These include the exclusion of unmetered street lighting supplies, except where a distributor can identify the unmetered supplies from its historical performance data.

Source: Compiled using AER 2017, Draft Amended Service Target Performance Incentive Scheme, see https://www.aer.gov.au/system/files/AER%20-%20Draft%20amended%20service%20target%20performance%20incentive%20scheme%20-%20December%202017.pdf

[122] See notes on STPIS parameters in Appendix A of AER 2017, Draft Amended Service Target Performance Incentive Scheme.

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