Monitoring, Evaluation and Compliance Strategy 2020-25
SA Power Networks
September 2021

1. Introduction

About SA Power Networks

As our State's primary electricity distributor, SA Power Networks plays an important role in our community, managing the distribution network that delivers electricity to 910,000 homes and businesses across South Australia. We are recognised as an industry leader in reliability and safety. We are also number one for efficiency on an individual and a state-by-state basis as measured by the Australian Energy Regulator and that has enabled us to keep a lid on our prices over many years - holding increases in line with inflation since 1999. Currently our charges account for approximately a quarter of the average residential electricity bill.

SA Power Networks has the oldest fleet of network assets in the National Electricity Market and we currently maintain them with a remarkably low level of expenditure with, on average, only 0.30% of our assets being replaced per year. As those assets continue to age, delivering the levels of service and new services that our customers are expecting will be challenging. To do so will require increased investment in asset maintenance and replacements and there has been a step change in our asset replacement rate in the last five years .

Customers and stakeholders

SA Power Networks customers and stakeholders are widespread, diverse and evolving. We serve almost the entire population of South Australia and as the state develops the number of customers we serve continues to grow. Our customers' and stakeholders' expectations are changing rapidly as technological changes sweep through the energy industry. They want to be able to use the network in new ways and be both exporters as well as consumers of energy. They want us to provide better information about outages and predicted restoration times, and they want to understand our costs better. Above all, our customers want us to:

1. keep prices down;
2. maintain our reliability and safety; and
3. carefully transition to a new energy future in a prudent way.

Monitoring, evaluation, and compliance strategy

SA Power Networks is required by our electricity distribution licence to comply with the South Australian Electricity Distribution Code (**EDC**). EDC clause 2.6 requires us to annually prepare a Monitoring, Evaluation and Compliance Strategy (**MECS**) to achieve the service standards detailed in clauses 2.1 to 2.4 of the EDC. The service standards relate to:

- Customer service measures (clause 2.1),
- Reliability measures (clause 2.2),
- Guaranteed Service level (**GSL**) payments (clause 2.3); and
- Reconnecting a customer after their premises was disconnected[1] (clause 2.4).

[1] Only obliged to reconnect a customer where they have been disconnected and request the reconnection in no more than 10 business days of the disconnection, otherwise the reconnection timeframes do not apply.

This document details:

- the EDC Service standards,
- Asset management practices,
- Emergency management practices,
- Risk management framework,
- our practices and processes to monitor, evaluate and take actions to comply with the service standards, and
- our historic performance against those service standards.

2. SERVICE STANDARD OBLIGATIONS 2020-25 RCP

2.1 Introduction

SA Power Networks is required by its distribution licence to comply with the service standards contained in the EDC. The EDC requires us to use 'best endeavours' to achieve the service standard targets for each year ending 30 June. The EDC clause 1.5.1 defines best endeavours as to act in good faith and use all reasonable efforts, skill and resources.

As the service standard obligation is to use best endeavours we can still comply with a service standard obligation, despite not achieving the target, provided that we can demonstrate that we have used best endeavours.

The following sections summarise the four categories of service standards and the targets (where specified) for the 2020-2025 Regulatory Control Period (**RCP** – ie 1 July 2020 to 30 June 2025).

2.2 Customer service measures and targets

2.2.a *Customer service measures*

Two customer service measures relate to communication with customers and measure how quickly we respond to customers enquiries by both telephone and written responses. "Written enquiries" includes emails and Facebook 'posts'.

2.2.b *Customer service targets*

SA Power Networks is required to use best endeavours to meet the following customer service standards for each year ending 30 June.

Category	Customer service measure	Target
Customer service	Time to response to telephone calls	85% within 30 seconds
Customer service	Time to respond to written enquiries	95% within 5 business days after receipt of the written enquiry

Achieving the telephone response target means that for every 100 telephone calls received we must answer at least 85 calls within 30 seconds. This response rate applies to five specified telephone numbers including the Faults and Emergencies call number. The EDC defines what is an answered telephone call.

Likewise, achieving the written response target means that for every 100 written enquiries we receive (includes email and Facebook enquiries) we must respond to 95 or more of those within five business days.

2.3 Reliability performance measures and targets

2.3.a *Reliability measures*

Reliability standards for the distribution system are:

- Unplanned System Average Interruption Duration Index (**USAIDI**) — measures the average time in minutes that customers are without their electricity supply because of unplanned interruptions on the distribution system in the year ending 30 June;
- Unplanned system average interruption frequency index (**USAIFI**) — measures the average number of unplanned interruptions customers experience to their electricity supply in the year ending 30 June; and
- Restoration of customers' electricity supply (**RCES**) — measures the percentage of customers who will on average have an unplanned interruption to their electricity supply where the duration exceeds a specified number of hours in the year ending 30 June.

These measures exclude planned interruptions and unplanned interruptions due to failures of the transmission network, generation failures, load shedding and failures in a customer's electrical installation. Further, the reliability service standard targets exclude interruptions that start on a Major Event Day (**MED**)[2] which normally result from extreme weather events, with typically about 3-4 MEDs occurring per year. The normalised reliability targets which exclude MEDs are designated with an 'n' (eg USAIDIn).

2.3.b *Feeder categories*

The EDC specifies reliability standards applying to each of the following four feeder categories:

- Central Business District (**CBD**) feeder – means a high voltage overhead powerline or underground cable in the CBD area supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection between high voltage feeders;
- Urban feeder – means a high voltage overhead powerline or underground cable, which is not a CBD feeder, and supplies a three-year average maximum demand over the three-year average feeder route length of greater than 0.3 MVA/km;
- Rural Short (**RS**) – means a high voltage overhead powerline or underground cable which is not a CBD feeder or urban feeder with a total feeder route length less than 200 km; and
- Rural Long (**RL**) feeder – means a high voltage overhead powerline or underground cable which is not a CBD feeder, urban feeder or a rural short feeder.

[2] A MED is any day where the contribution to distribution system USAIDI exceeds an annually calculated threshold which is around six minutes due to unplanned interruption that commence on a calendar day (ie midnight to midnight), this compares to an average for a non-MED of about 0.4 minutes.

The table below highlights information about each feeder category:

	CBD	Urban	RS	RL
Areas supplied	Part of the Adelaide square mile.	Greater Adelaide Metro Area and some parts of large regional towns	Eastern Hills (50%), Fleurieu Peninsula, Riverland and parts of large and medium regional towns.	Barossa, Eastern Hills (50%), Most of Eyre Peninsula, KI, Mid-North, Murraylands, South East, Upper North
% of customers	0.8%	69%	15%	15%
Circuit length of powerline (km)	300	26,000	13,700	49,300
Annual Consumption (GWh)	500	6,800	1,300	1,300

2.3.c Establishment of the reliability of supply targets

The Essential Services Commission of South Australia (**ESCoSA**) in its process to establish the reliability of supply standards for the 2020-2025 RCP discovered that most customers were satisfied with their current electricity supply reliability and were unwilling to pay for improvements. Therefore, ESCoSA decided that the reliability service standard targets should reflect the average historic reliability of the four feeder categories. They decided to use the ten-year period (ie 1 July 2009 to 30 June 2019) to determine the historic average performance.

There is large annual variation in the reliability performance for each feeder category, often related to the severity of weather events in a year. For example, the Rural Short feeder category USAIDIn has varied from a best of 143 minutes (2014/15) to a worst of 283 minutes (2009/10). As a consequence, the reliability service standard now includes a Reporting Threshold (**RT**), which represents the normally expected variation in reliability for a feeder category. SA Power Networks must demonstrate the use of best endeavours where the reliability of a feeder category is worse than the RT. The RT has been established at a level that, with normal variation in reliability, it should typically require SA Power Networks to demonstrate the use of best endeavours once every five years.

2.3.d *Network reliability service standards*

SA Power Networks must use its best endeavours to achieve the following minimum network reliability standards for each year ending 30 June.

Measure		CBD Feeders	Urban Feeders	Rural Short Feeders	Rural Long Feeders
USAIDIn (average minutes off supply per customer per annum)	Target	15	110	200	290
	Reporting threshold	20	125	220	330
USAIFIn (average number of supply interruptions per customer per annum)	Target	0.15	1.15	1.65	1.75
	Reporting threshold	0.20	1.35	1.85	2.10

As highlighted above, these measures exclude interruptions that start[3] on MEDs. MEDs are days of significant events where the organisation shifts from normal operation mode to emergency operation mode.

2.3.e *Network restoration standards*

SA Power Networks must use its best endeavours to achieve the minimum network restoration time targets. The proportion of the customers in each feeder category that experience unplanned interruptions that exceed the defined time periods, in hours, are set out in the following table for each year ending 30 June.

Target	Single interruption duration	CBD Feeders	Urban Feeders	Rural Short Feeders	Rural Long Feeders
Percentage of total customers in each feeder category per annum	Interruption equal to or greater than 1 hour	11			
	Interruption longer than 2 hours	4	27		
	Interruption longer than 3 hours		11	27	
	Interruption longer than 4 hours				30
	Interruption longer than 5 hours			8	
	Interruption longer than 7 hours				10

[3] Where an interruption starts on a day and is restored in following days its contribution to reliability performance is accrued to the day it started.

SA Power Networks is required to report on how it has applied its best endeavours if its performance is worse than the RTs set out in the following table.

Reporting Threshold	Interruption duration	CBD Feeders	Urban Feeders	Rural Short Feeders	Rural Long Feeders
Percentage of total customers in each feeder category per annum	Interruption equal to or greater than 1 hour	13.5			
	Interruption longer than 2 hours	6.5	29.5		
	Interruption longer than 3 hours		13.5	29.5	
	Interruption longer than 4 hours				32.5
	Interruption longer than 5 hours			10.5	
	Interruption longer than 7 hours				12.5

2.4 Guaranteed service level payments

2.4.a *Introduction*

SA Power Networks is required to make guaranteed service level (**GSL**) payments where we do not:

- connect a new supply address on the date agreed or within six business days after the customer has met all the necessary preconditions,
- repair a streetlight which has gone out within five business days in metropolitan areas and ten business days in non-metropolitan areas (referred to as other areas), and
- minimise the frequency and the total duration of unplanned supply interruptions.

2.4.b *Connecting a new supply address*

SA Power Networks is required to connect a new supply address on the date agreed or if no date is agreed within six business days, provided the customer has met all necessary pre-conditions for connection. Where this is not achieved, we will pay the customer $65 dollars per business day that we are late to a maximum of $325.

This GSL payment only applies in situations where electricity supply is readily available and all that is required is to install a service to supply the customer.

2.4.c *Repair of streetlights which are out (SLO)*

SA Power Networks is required to repair a streetlight out (**SLO**) within five business days within Metropolitan Areas and ten business days for non-Metropolitan (other) areas.

SA Power Networks is required to pay customers $25 for each period (five or ten business days) until the streetlight is repaired. The EDC Clause 2.3.1(b) contains the details of when day zero is determined amongst other conditions.

2.4.d *Reliability GSL payments*

SA Power Networks is required to make reliability GSL payments to customers if the total number of unplanned interruptions and/or the total duration of all unplanned interruptions for a year ending 30 June exceeds the thresholds in the following tables and make the payment specified in the tables.

Table 1—Thresholds and payment amount - frequency of interruptions

	Threshold
Number of unplanned interruptions in a regulatory year	> 9
Payment (including GST)	$100

Table 2—Threshold and payment amounts - total annual duration of interruptions

	Threshold 1	Threshold 2	Threshold 3
Total annual duration (hrs) of unplanned interruptions	> 20 and ≤30	> 30 and ≤60	> 60
Payment (including GST)	$100	$150	$300

Customers' electricity accounts will be credited with their eligible reliability GSL payments in the quarter following the end of the regulatory year (ie typically in August each year). Payments will be made in respect of the supply address. Customers will receive an SMS or letter advising them of the reliability GSL credit that has been applied to their electricity account.

The above scheme excludes:

(i) interruptions caused by the following:

- (A) transmission and generation failures
- (B) disconnection required in an emergency situation (e.g. bushfire)
- (C) single customer faults caused by that customer

(ii) momentary interruptions (ie interruptions where the duration is three minutes or less)

(iii) planned interruptions, and

(iv) partial interruptions to a supply address such as:

- (A) interruptions that affect only one or two phases of supply at a supply address with three phase supply, and/or
- (B) interruptions to one connection point where the supply address has multiple connection points.

2.5 Reconnection after disconnection

In summary, where the National Energy Retail Rules (**NERR**) require SA Power Networks to reconnect a previously disconnected customer's premises, we must:

- reconnect on the same business day in the Adelaide Business Area and the Major Metropolitan areas, provided the request is receive by us prior to 5pm on the business days; and
- use best endeavours to reconnect on the same business day but in any event on the next business day, where the request is received after 5pm.

The EDC clause 2.4 details all the possible scenarios for a customer requesting reconnection and the timeframes required for reconnection or customer payment required to achieve those timeframes.

Under the deemed standard ongoing contract, under which reconnections are performed, the obligation to reconnect lapses if the customer does not request a reconnection within 10 business days of their disconnection. Therefore, the reconnection timeframes only apply if a customer has requested a reconnection of their premises within 10 business days of the disconnection.

Under the Australian Energy Regulator (**AER**) National Energy Retail Law (**NERL**) compliance framework, SA Power Networks is required to report quarterly any failures with our reconnection obligations to the AER. SA Power Networks had no instances during 2019-20 where we failed to reconnect a customer within the specified timeframe.

3. Infrastructure Asset Management

3.1 Introduction

The SA Power Networks distribution network is a lightly meshed system, serving around 900,000 customers and supplying the populated areas of the State of South Australia.

The distribution network in South Australia operates at 50 Hz and has a total of:

- more than 89,000 circuit kilometres of power lines operating at 132 kV, 66kV, 33kV, 19kV - SWER, 11kV, 7.6kV and 400/230 Volts (LV);
- 400 distribution zone substations which operate at voltages ranging from 132kV to 3.3kV;
- around 74,900 distribution transformers on the distribution system ranging in capacity from 5kVA to 3,000kVA with a total installed capacity of about 9,057MVA.
- around 1.087 million revenue meters (as of April 2021) which meter electricity supply to both high voltage and low voltage customers.

A Network Operation Centre is located at Keswick which provides supervisory control and data acquisition facilities (via the Advanced Distribution Management System (**ADMS**)), to monitor system conditions at distribution zone substations, and manage day to day emergency supply restoration and operational matters on the network.

The Kingscote Standby Power Station is located on Kangaroo Island adjacent to the Kingscote Substation. The generation assets provide an alternative source of supply to improve the reliability of supply in the event of loss of supply on Kangaroo Island and also for network voltage support.

SA Power Networks operates and maintains the electricity infrastructure in accordance with its distribution licence obligations to ensure that:

- The network performance meets the National Electricity Rules (**NER**) and the South Australian Electricity Distribution Code (**EDC**) relating to system security and performance standards
- Quality of supply is maintained to customers
- Operational risks and hazards are identified and managed
- The electricity infrastructure is secured to prevent unauthorised access
- Response to the risks presented by accidents and incidents involving electricity infrastructure is adequate and timely

3.2 Asset management

The SA Power Networks Board approved Asset Management Policy sets out the approach and principles by which SA Power Networks manage its assets.

As per this Policy, SA Power Networks is committed to employing good asset management that provides a safe environment for employees, contractors and the community; is driven by the levels of service that customers value; ensures regulatory obligations are complied with; deliver a prudent risk-based approach and fosters continuous improvement.

Supporting the Asset Plan Policy is the Strategic Asset Management Plan, Power Asset Management Plans and various investment plans.

3.3 Risk management framework

SA Power Networks applies a risk management approach to all business activities in order to not expose the business to unacceptable levels of risk.

This includes:

- a corporate Risk Management Framework which provides the structure and tools to be used by the organisation in order to achieve the desired outcomes;
- a Risk Appetite Statement that provides a view of the Board's risk appetite for key strategic areas of the business;
- an annual risk profiling process;
- regular review of the risk profile data;
- regular report to the Risk Management & Compliance Committee providing an analysis of the risk profiling data;
- ongoing audits of the risk profile data including the control regimes to facilitate best practice; and
- the appropriate training in risk management techniques and the policy requirements, in accordance with the approved annual training plan

SA Power Networks' Risk Management Framework is aligned with the Australian Standard on Risk Management AS ISO 31000.

Risk management considerations are to be incorporated into the planning, design, construction and operational phases of all activities.

The management of risks will include the purchase of insurance to cover potential losses associated with some risks.

See Section 5 for more detail.

3.4 Asset planning and creation

3.4.a Introduction

As the principal South Australian distribution network service provider, SA Power Networks primary responsibility is planning, building, operating and maintaining the South Australian electricity distribution network. Customer demand on the network can be influenced by many demand drivers including population, business and industry growth, tourism, technological changes (including rooftop PV penetration, integrated PV and storage system (**IPSS**) and electric vehicles), energy efficiency, climate changes and retail price changes.

3.4.b Distribution network planning

As a DNSP within the NEM, SA Power Networks must comply with the requirements relating to reliability and system security contained in Schedule 5.1 of the NER relevant to planning for future electricity needs and with the service obligations imposed by the EDC. SA Power Networks has developed its planning criteria to meet and maintain the reliability and security of supply requirements of the NER and EDC. Where the forecast load breaches the planning criteria (ie a network constraint) a suitable solution is sought whether this involves implementation of a major network augmentation, a deferral solution or a suitable contingency plan taking all risks and their associated consequences into consideration. The planning criteria is discussed in detail within the SA Power Networks Distribution Annual Planning Report (**DAPR**)[4].

Each year SA Power Networks prepares the DAPR to inform National Electricity Market regulators, participants and stakeholders about existing and forecast system limitations (constraints) on our distribution network, and where and when they are expected to arise within the forward planning period.

While demand at a state macro level is relatively flat, demand within planning regions varies. That is, growth in some parts of the network maybe offset overall by decreases in other parts of the network, but localised areas may still require network upgrades to increase capacity. Projects are developed to address these constraints and increasingly, quality of supply issues arising from increased uptake of PV systems.

Annual reviews identify likely projects for informing the required forward investment on necessary network augmentations for maintaining the reliability and quality of supply levels of service.

Asset planning starts with a review of annual load growth on the sub-transmission system and high voltage (**HV**) distribution network after each summer to identify capability and capacity constraints against defined planning criteria, considering any recent changes to the network including use of latest load recordings, generator connections (including PV and battery), system modifications and any new committed large load developments. It includes assessment of the network against specific planning criteria to enable prudent planning of the network's capacity, security and switching systems, for achieving the performance targets of the business over the medium to long term. The network asset planning strategy is based on the net projected impact of the factors influencing demand. The strategy aims to ensure electricity can be supplied to existing and new customers without breaching the planning criteria to ensure compliance with the NER and EDC.

Strategy for planning new network assets includes consideration of:

- **Connecting new customers on request**: Manage customer connections services in accordance with the SA Power Networks Connection Policy and National Energy Customer Framework (see Section 7.4).
- **Monitoring existing loads**: Each year, review peak loads on the network after summer for the impact of:
  - modifications that have occurred on the network including embedded generation and spot loads,
  - changes in spatial demand and consumption diversity,
  - impacts of Distributed Energy Resources (DER) such as PV systems and batteries, and
  - quality of supply.
- **Reviewing changes to equipment ratings**: Undertake annual reviews of equipment capacity and load transfer capability.
- **Comparing forecast against equipment ratings**: Compare the projected demand forecast against equipment capacity at key locations in the network for various planning criteria including normal operation and contingency conditions. The forecast includes any identified spot loads including any key State Government projects having a high probability of proceeding. The constraint capacity, or load at risk, takes into consideration the level of load SA Power Networks is prepared to allow to remain unsupplied following the performance of all available feeder transfers and the ability to connect a mobile substation in the event of a transformer outage.

[4] The DAPR can be found on SA Power Networks' website here

- **Capital budget**: SA Power Networks forecasting for augmentation programs is developed through a 'bottom up' approach with estimated costs developed using a set of standard component or unit costs.

3.4.c Asset planning

Building on our network risk forecasting methodologies we determine an 'actionable' work value for small to medium size jobs to help us make day-to-day decisions. Work value is the measure of the benefit of undertaking work on the asset. It is the combination of how much safety/reliability/fire risk we reduce and other benefits from undertaking the work. This work value is used to ensure effective investment decisions on smaller projects where a detailed cost benefit analysis is not warranted.

Safety is considered at every phase in the plant life cycle, from design to disposal. However, the earliest stages of the design process (during conceptual and planning phases) are the best places to design out hazards, incorporate risk control measures and design in efficiencies. This means thinking in advance about potential hazards and possible design solutions as the plant is manufactured, transported, installed, commissioned, used, maintained, repaired, de-commissioned, dismantled, disposed of, or recycled.

3.4.d Asset creation and renewal/replacement

In the lead up to creating an asset in response to an identified need in the asset planning phase, we consider what is the right asset to install. Where possible and prudent to do so, we have a bias towards repairing or refurbishing assets to extend their service lives. In addition to 'patching' in service assets we deploy refurbished transformers, switching cubicles and circuit breakers. Our active refurbishment programs have allowed us to extend the life of our assets and reduce the investment required to maintain risk and service levels. Where we do decide to install a new asset, we consider the future requirements for that asset. For instance, new switchgear is installed with remote monitoring capabilities to help us get visibility of energy flows on our network. We also consider non-network solutions where prudent to do so.

Historical asset risks, performance and standardisation of asset types are considered in developing equipment standards. Technical drawings ensure the asset design, construction and commissioning complies with the legislative requirements and industry codes of practice. This also applies to new and altered customer connections.

Testing and commissioning procedures are developed to ensure that new assets are safe and ready to connect to the network.

3.5 Asset operations

3.5.a Network Operations Centre (NOC)

SA Power Networks operates a Network Operations Centre (**NOC**) on a 24 x 7 basis that is responsible for:

- coordinating switching on the SA Power Networks distribution network to minimise risk to the safety of personnel, plant and continuity of supply,
- coordinating access to the network for work,
- directing and monitoring fault finding and repairs on the network, and
- managing the day-to-day risks associated with operation of the network.

The central, integrated and dynamic system used by the NOC for managing and monitoring the comprehensive distribution network is the Advanced Distribution Management System (**ADMS**). This system is also used for feeder automation to automatically restore supply to un-faulted sections of a feeder when a network fault occurs.

The NOC coordinates and controls all operational activity, both planned and unplanned, on the high voltage distribution network to ensure safety, compliance and performance. It reviews, coordinates and directs switching and isolation to permit the safe access for field workers to carry out work on electrical assets.

The NOC receives information of supply interruptions through both remote monitoring systems (eg Supervisory Control and Data Acquisition (**SCADA**)) and through customer reports received by the call centre. Supply interruption details are recorded in the Outage Management System (**OMS**) which is used to consolidate, prioritise and dispatch the work to field crews. Those crews then undertake investigative work to identify the cause of the supply interruption, then under the direction of the NOC, undertake remedial work and restore supply to customers. The HV Controllers direct field crews during the supply restoration process to ensure safe operational procedures are followed while maintaining reliability of the network.

SA Power Networks has detailed network operation procedures and contingency plans in place which are reviewed and updated on a regular basis. The contingency plans are developed for critical assets where there is an identified high consequence of failure such as widespread supply failure, risk of plant damage, or risk to public health and safety.

3.5.b Advanced Distribution Management System

The ADMS is a central, integrated and dynamic system used for managing and monitoring the comprehensive distribution network. It is currently used in the NOC as the primary SCADA master system, as well as for feeder automation. It is also used to initiate load shedding when directed by AEMO as well as for expediting the feeder disconnection process during high-risk fire days.

The ADMS provides:

- real-time execution and operations: visibility and control across the distribution network settings,
- a network operational model: a representation of the electrical transmission network, subtransmission system and distribution network that represents the network connectivity,
- integration with other enterprise systems: enabling of integration with the SAP works management system, OMS, protection settings database and outlook email system, and
- off-line network analysis and operations planning: 'what if' scenarios to be undertaken without impacting the operational system.

The connected geographic network model has been built in ADMS used to support all planned and unplanned HV switching from mid-2018. This means all HV switching writing and execution will be conducted using electronic HV switching programs in the ADMS. By performing electronic HV switching on a connected network model in ADMS leads to increased visibility of the real-time state of the network, potentially leading to more efficient supply restoration times and a decrease in HV switching incidents.

The ADMS supports the future operations of the network through having a live, real-time and connected network model, providing the central platform to meet future challenges, such as LV management, DER management, and automatic network re-configuration.

3.5.c Feeder automation

The purpose of feeder automation is to provide an automated fault location, isolation and supply restoration system to un-faulted sections of the feeder within the ADMS to improve customer reliability. In summary, the feeder automation system:

- provides a centralised means by which to determine fault location on feeders based on telemetered data from field devices,
- determines the isolation points for the faulted line section and the automatic execution of the switching to achieve that isolation,
- determines the most ideal supply restoration options for healthy feeder sections and automatically conducts the restoration based on limitations of the power system, and
- collects and collates fault data from relevant field devices for situational real-time display to operators.

Since commissioning, benefits have included process improvements by standardising installation, commissioning, and configuration philosophies, as well as operational improvements by installation of remote operable switching devices. The increase in remote switching capability at multiple points down the feeder, as well as the introduction of remote tie points, has improved fault finding speeds, switching efficiency and supply restoration times. The feeder automation system has improved supply restoration procedures and has allowed for remote restoration of healthy sections of line before field crews have even reached the site. This can reduce restoration times from hours to minutes (or less) preventing or minimising financial penalties to SA Power Networks arising from the fault. Full automation to restore all un-faulted parts of SCADA enabled feeders commenced in mid-2018.

3.6 Maintaining our assets

3.6.a Condition monitoring

Asset inspections and condition monitoring are aimed at finding defects or condition issues before asset failure occurs and provide information on whether asset maintenance or asset renewal/replacement is required.

Comprehensive asset inspection and condition monitoring programs are undertaken across line and substation assets to identify signs of asset deterioration. The many assessment techniques used include visual inspections, thermography, partial discharge tests and other diagnostic techniques to determine the condition of the assets. The inspection and condition monitoring programs happen on a cyclic basis in line with the corrosion zone an asset is in (ie how quickly it is likely to deteriorate), the bushfire risk zone an asset is in (ie how big the consequence of a failure is likely to be) and/or the criticality of the assets (ie how many customers are supplied by the asset). The frequency of inspection cycles across the network continues to be optimised. We also actively monitor network reliability performance to identify—and thus address —emerging trends.

We use inspections to collect additional asset data to improve our understanding of our asset base. Over the last couple of years, we have been actively improving our asset knowledge by relating our work to specific assets so we can start building up a history of those assets. Previously asset data for line assets was only collected at a feeder level rather than to the specific asset, such as a pole.

When a significant or unexpected failure does occur, we undertake a detailed equipment failure investigation, which contributes to our knowledge of asset failure modes. We continue to expand our knowledge that links asset failures to the observed condition during cyclic inspections. This is improving our understanding of asset risk and informing our policies, strategies and practices.

A key input into our asset management plans is benchmarking. By comparing ourselves with similar organisations we can identify areas for improvement, understand what we are doing well and work collaboratively with our peers to share knowledge.

We employ predictive models to understand the investments needed to manage the risk and service from our assets. These are described in more detail in our Power Asset Management Plan.

Our trials cover emerging technology such as the use of autonomous drones, fixed wing aircraft, specialised condition monitoring equipment and laser scanning technology referred to as light detection and ranging (LiDAR). We seek to extend our capability to collect timely data by considering other methods of collection: field crew, customers, and new technology.

We are continuing our journey of transitioning to condition-based inspections. This includes further development of our inspection tools to support information capture directly against our assets for more field-based activities beyond the already implemented functionality for line inspections. We are expanding the tools to cover vegetation management audits, pre-bushfire patrols, substation inspections, bulk lights, DC batteries and thermographic inspections. Further enhancements are also being deployed to support work valuing and work visibility (see Section 3.6.e below)

All staff and contracted asset inspectors are trained and accredited to Certificate 2 in asset inspection.

3.6.b Asset data collection

Testing and commissioning procedures are developed to ensure that new assets are safe and ready to connect to the network. Updating the information systems is an ongoing task in life cycle asset management. A critical stage in the life cycle is when the asset is commissioned on the network. This is the point at which all the relevant systems are updated with as much available data as possible.

Maintenance and refurbishment activities allow asset condition data to be collected at other stages of the asset life cycle.

3.6.c Renewal/replacement strategies

3.6.c.1 Risk based replacements

SA Power Networks' long and short-term renewal replacement strategies adopt a risk based approach. The identification of defects or condition issues in deteriorating assets are determined through the asset assessment process to prioritise an appropriate intervention based on risk. Assets that fail in service are typically replaced immediately where decommissioning, repair or refurbishment options cannot be economically justified.

Condition based risk management (**CBRM**) decision support tools are in development for the quantification and management of asset risk and end of life planning for all major asset types, with targeted programs of replacement used to address asset sub-populations with demonstrated issues of operational performance, design flaws or technical obsolescence.

The failure consequences modelled within CBRM include:

- Safety: minor, significant or major injury to the community and employees because of an event,
- Network performance: financial penalties imposed if an event causes an outage in the form of customer interruptions (e.g. system average interruption duration and frequency index impacts),
- Environment: cost of environmental clean-up/penalties as a result on an event,
- Capex: capital investment required to renew/replace a failed asset, and
- Opex: operational cost associated with a failed asset, including operational cost to restore power in the event of a failed asset.

The CBRM models calculate an individual asset's likelihood of failure based on the observed population's historical failure rates. Quantifiable measures of condition, performance, failure consequences and asset deterioration allow risk to be modelled for individual assets and forecast for future years. The change in risk profile over time is forecast by CBRM which calculates the deterioration over time for individual assets which can then be aggregated at the asset class level or by system.

SA Power Networks also has an active program to rationalise the number of equipment variations on the network. Reducing the types of equipment and plant deployed reduces the number of safe operating procedures that need to be developed, maintained and referred to. This provides a safer environment for employees, contractors and the community and reduces the whole of life costs as its easier to keep spares and dispose of equipment.

3.6.c.2 Targeted replacements

Targeted replacement programs are treated separately to CBRM modelling as outliers to the general population (or non-modelled asset types) with risks related to specific design flaws or performance issues (beyond age related degradation) that make them prone to early failure without specific intervention. These programs are referred to as 'push work'[5] and target replacement of a group of assets deemed to present a high-risk requiring replacement.

3.6.d Vegetation management

The purpose of the vegetation management program is to reduce the risks associated with vegetation contacting powerlines and causing bushfire, public safety and interruptions to electricity supply. It is designed to maintain statutory clearances between trees and power lines as a critical part of bushfire risk mitigation. This involves the clearance of vegetation of all kinds from public supply lines and naturally occurring vegetation from private supply lines in accordance with the Regulations to the Electricity Act 1996 and the requirements of the Native Vegetation Act 1991.

SA Power Networks power lines are inspected on an appropriate cycle[6] in bushfire risk areas and up to three-year cycles in non-bushfire risk areas to identify vegetation cutting needs to comply with clearance zones specified in the Vegetation Clearance Regulations and scope cutting work as specified in Vegetation Services Work Instructions.

SA Power Networks vegetation clearance scoping and cutting is carried out by our vegetation clearance contractors. This work is audited by an external party and by SA Power Networks Officers to ensure that vegetation has been cleared in compliance with the Electricity (Principles of Vegetation Clearance) Regulations.

3.6.e Value and visibility

A key feature of SA Power Networks' asset management decision making process is based on return on investment. The process of valuing work enables SA Power Networks to select the optimum maintenance and replacement strategy for each asset class that is technically feasible, economically viable, and delivers an acceptable residual risk while delivering customer value.

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5 Push work is well coordinated and planned to a required schedule. Ideally major projects and date dependent work should comprise the majority of pushed work.

6 The cycle is determined based on vegetation growth rates and the extent that SA Power Networks is able to clear vegetation away from powerlines to keep vegetation outside the clearance zone until the next scheduled inspection cycle.

The value and visibility (**V&V**) tool is the current operational tool used on line assets and being implemented on substation assets to assess the level of risk present in the network arising from identified defects and other required works for small and medium repeatable jobs by:

- **Having an agreed comparison of work value:** the sum of the reduction in risk and the benefits being gained by undertaking work whether it be capital or operating expenditure
- **Making work visible to everyone:** enables works in close geographic proximity to visible for improved planning
- **Enabling bundling:** grouping together other less urgent (secondary) work to augment the primary task ('anchor jobs')

The V&V process is currently applied to SAP work management system notifications (identified works) including distribution defects (**DD**), fault management notifications (**FM**), reported quality of supply faults (**QS**), customer negotiated services (**CN**) (e.g. new service connection infrastructure), substation defects (**SD**) and identified reliability works (**RI**). It provides an additional level of defect scrutiny to allow identified work to be valued for prudency (confirms work is required) and efficiency (prioritise the work that provides the greatest reduction in risk for the investment). The required maintenance or renewal/replacement work is prioritised based on greatest return on investment (e.g. priority given to low cost; high value work).

3.6.f Asset performance review committee

The purpose of the Asset Performance Review Committee is to monitor asset inspection results, trends and asset failures occurring in the field, which may be symptomatic of emerging problems, and to report the findings to the Network Management group.

The Asset Performance Review Committee (**APRC**) is responsible for reviewing:

- Interruptions referred by the SPS Steering Committee
- Equipment failure investigations
- Asset inspection results

3.6.g Service Performance Scheme (SPS) steering committee

The main purpose of the SPS Steering Committee is to ensure that SA Power Networks achieves its customer service and regulatory obligations for reliability of supply (as detailed in the EDC and in the STPIS).

The purpose of the SPS Steering Committee is to:

- Deliver optimal reliability and SPS outcomes for SA Power Networks
- Monitor progress, performance and trends
- Review high impact events and causes
- Consider and approve mitigation strategies
- Identify SPS opportunities and threats
- Seek strategic management solutions, projects, ideas and innovations
- Challenge the current norms
- Facilitate agreement and provide endorsement

Decisions from the SPS Steering Committee feed into the Reliability Management Plan. The SPS Steering Committee meets monthly and comprises the GM Network Management, key Network Management and Field Services Operations Managers.

3.7 Improve resilience

3.7.a Background

Our network spans a vast distance and is exposed to increasingly severe and frequent weather events. The consequent extended interruptions when our assets are damaged by those events has clearly been felt by our customers. During our engagement sessions in 2017 reliability emerged as their highest priority. Customers supported hardening the network against major storms in priority areas and ensuring acceptable levels of reliability for all customers.

3.7.b What this means in practice

The Resilience Program aims to address deteriorating reliability during major event days. The program's scope is to harden the most vulnerable sections of the distribution network against storms and lightning to reduce the impact on customers on those days. The program uses a combination of strategies including:

- re-insulating vulnerable sections of overhead lines to minimise the possibility of insulator failures due to lightning;
- altering network asset configuration/standards to minimise the chance of vegetation outages from outside the prescribed clearance zone;
- installing mid-line switches to reduce the number of customers subject to storm related interruptions; and
- undergrounding sections of the overhead network that are repeatedly damaged during storms.

The Resilience Program is different from managing underlying network reliability as it is focused on improving the performance of vulnerable parts of our network during major storms, and thus reliability to our worst served customers.

4. EMERGENCY MANAGEMENT

4.1 Summary

Emergency management is a key duty undertaken by SA Power Networks, and its purpose is to:

- minimise the risk to public health and safety;
- minimise the duration of supply outages;
- minimise the number of customers impacted by supply outages;
- minimise the risk of plant damage; and
- coordinate and support external emergency authorities.

Where high volume or emergency conditions occur, an appropriate emergency response level (**ERL**) or fire danger level response is initiated. For escalated or forecast emergency situations, an Emergency Management Team (**EMT**) is convened to coordinate SA Power Networks response to network emergencies and liaise with other organisations including State Government Emergency Management organisations. All activities and decisions by the EMT Team are recorded and all significant emergency response efforts are subject to meticulous review to identify opportunities for improvement.

4.2 Seasonal preparations

SA Power Networks annually undertakes an extensive seasonal preparedness programme that both minimises impacts on customers from outages during heatwaves (and high electric loads), storms, impacts from the penetration of solar panels on the electricity grid and also to prevent bushfires. The program considers activity such as the appointment of personnel to key operational roles, logistics (eg availability and access to material) and distribution network condition. These preparations are listed in the Seasonal Preparations Plan which details actions to mitigate the risks of:

- bushfires starting from SA Power Networks' assets,
- widespread and long duration power outages during heatwaves,
- system stability and security when SA grid demand is low due to high rooftop generation, and
- inadequate resourcing when wind and/or lightning storm weather is forecast.

Each year we ensure we have sufficient employees trained to undertake specific roles as part of a whole of business response to significant events. We focus on completing the training prior to the declared bushfire risk season. We also write to every registered life support customer to request them to provide any changes to their contact details and that they should have action plans in place in the event of power outages.

4.3 Field crew resourcing levels

SA Power Networks understands that a storm can hit at any time of the year. We have a compulsory annual leave "ceiling" requirement and a range of other resourcing arrangements/schemes that ensure that we have a balanced availability of field personnel across all days of the year (both working days and holidays). This ensures a minimum 80% of crews are immediately available at any time to respond to a major event.

In response to a forecast of an extreme weather event, we may send crews home to ensure they are available to respond to the emergency or we may pay employees an extra allowance to make themselves available to respond at short notice to ensure that we have sufficient resources available to effectively respond to that event.

Further, we train non-field crew based staff so that they can attend wires down situations to the ensure the public are kept safe until crews are available to respond and complete repairs.

4.4 Restoration priorities

Responding to a major significant weather event is a complex exercise entailing a multitude of information sources and decisions that reflect many trade-offs. To assist in this endeavour, SA Power Networks operates according to restoration priorities. The restoration priorities are provided in the table below and were developed in conjunction with State Government emergency service organisations in 2011[7]. It should be noted, however, that the overriding priority across all jobs is the safety of people, of both powerline workers and the wider community. As a result, prioritisation of work is assessed with primary regard to reports of wires down that may otherwise pose a risk to the community.

In practice, outage jobs are categorised into operational work areas and issued to available crews on the basis of the priorities listed below. Re-prioritisation may occur in response to new outages, or as new information is available.

Priority	Customer/Load
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

In general, an interruption affecting large numbers of customers is given priority over an interruption affecting small numbers of customers. However, consideration is given to restoring an interruption affecting small numbers of customers where those customers have been without supply for a long period of time, compared to, say, a recent interruption affecting a large number of customers.

4.5 Customer communication

4.5.a Faults and Emergency Contact Centre

SA Power Networks' Faults and Emergency Contact Centre (ie 13 13 66) is staffed 24/7 to ensure that customers can contact us to report interruptions to their electricity supply and report emergencies (eg wires down).

[7] The restoration of supply priorities are currently being reviewed with these organisations.

4.5.b *Satellite contact centre*

In addition to our regular Faults and Emergency Contact Centre we have established a capability to quickly establish a Satellite Contact Centre (SCC) during major events when call volumes are very high, to ensure that all faults and emergency calls are handled promptly. We ensure that we have sufficient employees trained to be called on to staff the SCC. The SCC generally takes inbound calls from the Faults & Emergencies line (13 13 66) but may also make outbound calls to Life Support Customers or the worst affected customers during an event to better understand customer impacts/priorities.

4.5.c *Social Media*

SA Power Networks employs Facebook, Twitter, Instagram and the media to keep customers informed during major significant weather events. In addition, we use our 'Power at My Place', to send SMS to customers about interruptions to their electricity supply and updates of estimated supply restoration times. We provide 'posts' to customers about delays in restoration times and photographs of the types of damaged to infrastructure.

4.6 Emergency Response (including Major Event Days)

The Emergency Response Manual details SA Power Networks' procedures for emergencies associated with SA Power Networks' assets, from the declaration of an emergency until cessation by an authorised person. It specifies the roles and responsibilities for all groups that respond to network emergencies, including outages to supply, network security, and environmental incidents.

The Emergency Response Manual has four response levels from the lowest being Emergency Response Level zero (**ERL0**) being for normal daily operation to the greatest being ERL3 (see Table 3 below). There are four phases associated with Emergency Response being Preparation, Pre-Event, during the Event and Post-Event (ie review). The Pre-Event phase activities include:

- Monitor weather to confirm likely progress of escalating events
- Determine regional resources
- Check that resource levels are commensurate with forecast event 'size'
- Place personnel on standby as required
- Arrange for Emergency Management Team (**EMT**) to meet and prepare a response plan.

The EMT:

- Ensures that there is a coordinated whole-of-business response to the network emergency
- Regularly monitors progress of the operational response and ensures that operational response goals, priorities and objectives are being met, including requirements for stakeholder communications
- Ensures operational issues are resolved

The EMT responsibilities are to develop a suitable emergency operational response plan, implement it, monitor its progress, and ensure that supply is restored within agreed corporate objectives and priorities. The plan must account for:

- Current and forecast impacts on the network of the emergency event
- Where the impact is from the weather, what are the current and forecast impacts of the weather

- Current and projected resource requirements to manage the network, undertake field operations and manage customers.

Table 3 - Emergency Response Levels

Network Emergency Level	Event Characteristics	Summary Response
ERL0	– Normal daily operation	– Normal response
ERL1	– Localised strong to gale force winds – ≤ two days high (maxima, minima) temperatures – Localised Severe lightning	– Resources increased in impacted areas – Resources placed on standby
ERL2	– Widespread gale or strong winds – > two days high (maxima, minima) temperatures – Widespread Severe lightning	– Incident Response Manager (IRM) convenes Emergency Management Team (EMT) – EMT prepares operational response plan – Continuous shift rostering
ERL3	– Widespread, protracted, multi-day Network restoration event	– Continuous shift for all operational staff including EMT, Call Centre and field crews – IRM convenes EMT – CMT[8] is convened

[8] CMT ≡ corporate Crisis Management Team

5. Managing Risk

5.1 Introduction

The electricity network has the potential to start a major bushfire, cause widespread property damage, and injure or kill staff or members of the public. This section describes the risks SA Power Networks faces in delivering service to its customers. Risk is often expressed in terms of a combination of the likelihood of an event occurring and the consequences of an event.

The SA Power Networks Risk Management Policy defines risk as:

The chance of something happening that will have an impact upon objectives. It is measured in terms of consequence and likelihood.

SA Power Networks has adopted an enterprise risk management approach to managing risk as documented in the Risk Management Framework. The framework includes instructions and templates for risk assessments. The Asset Management Policy requires asset managers to manage assets to satisfy customer service needs, meet licence and regulatory obligations, and provide a safe environment for employees, contractors and the community.

Key components of the risk management system at SA Power Networks includes:

- **Risk Management Policy**: Outlines the risk management approach to all business activities to ensure that the organisation maximises opportunities without exposing the business to unacceptable levels of risk.
- **Risk Appetite Statement**: Provides guidance in decision making around strategic risks such as safety, bushfire, asset management, unregulated business and workforce capability.
- **Risk Management and Compliance Committee**: Oversees and makes recommendations to the Board on the risk profile of the business and ensures that appropriate policies and procedures are adopted for timely and accurate identification, reporting and management of significant risks to the business.
- **Risk Management Framework**: Outlines how risk management information should be used and reported within the business as a basis for decision making and accountability; includes risk assessment templates and guidance of application.
- **Corporate risk register**: Identifies key whole-of-business risks that have the potential to impact the achievement of the business strategic objectives. They are not a reflection of the 'top ranked' risks for the business (by risk rating), but are risks that all workers should be aware of. Dedicated cross departmental effort is required to manage these risks.
- **Departmental risk registers**: Department specific risks that require controls to be in place. While there is crossover between departments for certain risks, they will only be elevated to the corporate risk register where there is a potential impact a large cross section of the organisation.

Risks are assessed at both the corporate level (top-down) and at an individual asset level (bottom-up). The risk registers are reviewed formally and reported to the Executive Management Group, Risk Management and Compliance Committee and CKI (Hong Kong) on a six-monthly basis.

5.2 Managing external risks

SA Power Networks has a risk management framework that establishes the methodology for identifying, measuring and tracking external risks on an ongoing basis. The business identifies the risk for inclusion in risk registers. The risk registers document how these are managed and identifies risk owners.

5.3 Managing operational risks

Operational risks are mitigated by operational procedures and standards including preparation of detailed contingency plans for all credible critical contingencies which could lead to undesirable outcomes such as plant damage, loss of supply or compromises in public safety.

5.4 Managing asset risks

Asset risks are mitigated by understanding the impact of asset failures on delivering the service to the customers and stakeholders and using good asset management practices during the life cycle of an asset.

Asset defects identified through inspection and condition monitoring processes (see Section 3.6.a) have their risk quantified and the estimated cost to repair or replace the defect determined through the value and visibility process (see Section 3.6.e). As of mid-2018, substation assets use a previously applied risk prioritisation method, however a transition plan is in place towards migrating substation defects to the value and visibility process. This process is actively used to manage the identified network risks enabling the prioritisation of resources across various work types. The results are used to compare the relative risk and cost of works to aid in day-to-day decision making.

CBRM decision support tools (see Section 3.6.c.1) assist in allocating limited funding to maximise the reduction in asset risk. The CBRM models use asset performance and condition data to calculate both current individual and aggregated asset class condition and risk information and determine the impact of different intervention strategies on risk and condition over time.

SA Power Networks is continually improving its asset management practices and systems to provide a balanced outcome that meets shareholder, risk, compliance and customer objectives. A major part of that improvement has been the continuation of a transition to a risk-based replacement approach for assets through expanding the scope of coverage of condition based risk management (CBRM). This transition requires good asset condition data combined with improved analytical techniques enabling asset risks to be quantified. Increased condition monitoring will provide better knowledge on the condition of the assets to enable better asset decisions, such as replacement time and maintenance intervals and to manage risks associated with asset operations.

6. Monitoring, Evaluation & Compliance Strategy

6.1 Introduction

SA Power Networks' objective is to achieve the service standards specified in the EDC sub-clauses 2.1 to 2.4 for each year ending 30 June.

SA Power Networks has implemented, and continuously improves, its procedures and practices to monitor performance, evaluate that performance, implement improvements to address any long-term decline in performance (ie maintain historic performance) and to improve historic performance where the benefit to customers exceeds the costs of those improvements. Further, where the reliability of a feeder declines, we will implement improvements to correct that decline (ie return to reliability levels that existed prior to the decline).

6.2 Reliability strategy

6.2.a *Summary*

The following summaries the ongoing reliability management activities that support the interruption prevention activities pursued to manage SPS, GSL and customer service impact.

Stream	Activities
Monitoring & Reporting	– Reliability performance reporting – SPS Steering Committee – Asset Performance Review Committee – Daily interruptions, are investigated to determine if there are any negative trends
Planning	– Maintenance task review and prioritisation – Asset restoration and preventive maintenance prioritisation – GSL interruption payment risk assessment – Protection management plan (Annual)
Investigation & Support	– Network Duty Officers – Reliability cause analysis – Equipment failure investigation and trending – Poor performance feeder and equipment investigation and remediation*
Prevention	– Repeat fault finding procedures – Maximum restoration time policy – Planned interruption management – TF and LV load management – Reliability performance education – Reliability management best practices

6.2.b *Maximum restoration time policy*

We do everything within our control to restore electricity supply to all customers as soon as possible following an unplanned interruption. SA Power Networks has a maximum restoration time policy where our field crews or work dispatches are responsible for escalating an unplanned interruption where number of customers or/and the forecast restoration time exceed a specified threshold. Where an unplanned interruption is escalated a leader is responsible for resolving any resourcing (eg labour, materials, vehicles etc) issues (within authority levels) in an attempt to achieve or better these thresholds. If the leader cannot resolve the resourcing constraint, they must escalate it to their leader.

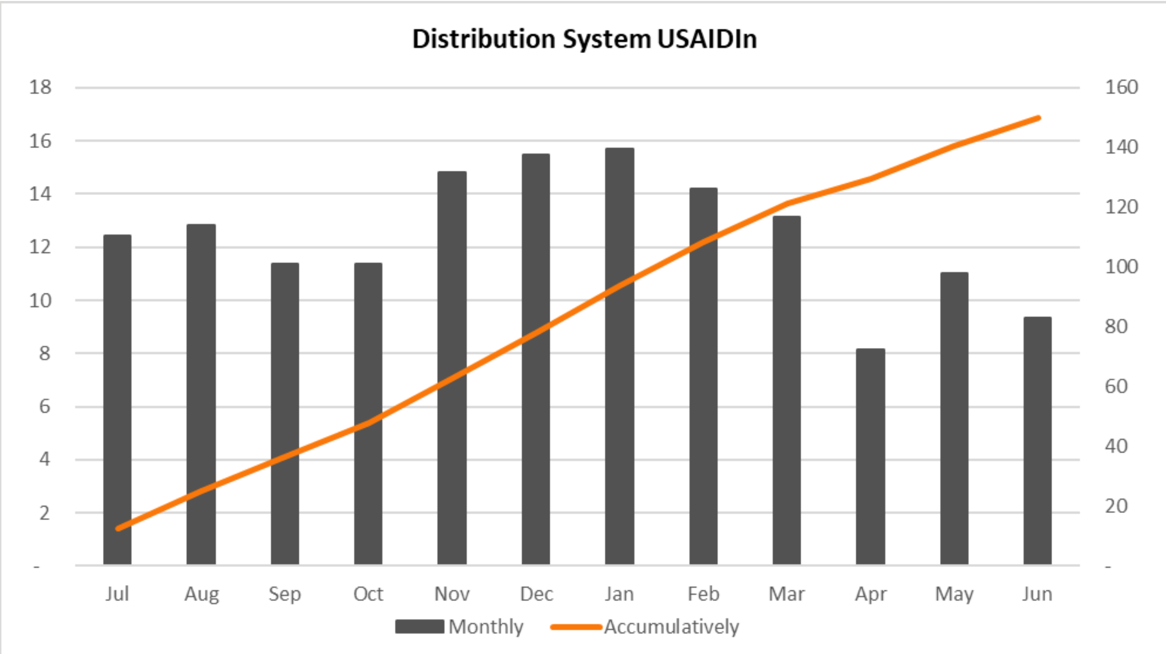
When it is confirmed that the interruption time will exceed the threshold then the Leader must ensure that the matter is promptly escalated to their Operations Managers, General Manager Field Services (GMFS) and Incident Response Manager (IRM). Where it is apparent that the thresholds are not achievable then the Operations Manager or their delegate are responsible for advising Customer Relations and Media Relations. In conjunction with these groups, customer and media management strategies will be implemented.

6.3 Monitoring service performance

To effectively monitor our performance against the service standards, we have calculated the historical average monthly performance to develop a twelve-month profile (based on outage data for the 10-year target setting period) that tracks service performance with the service standard targets. These profiles are not linear and can have significant monthly variations.

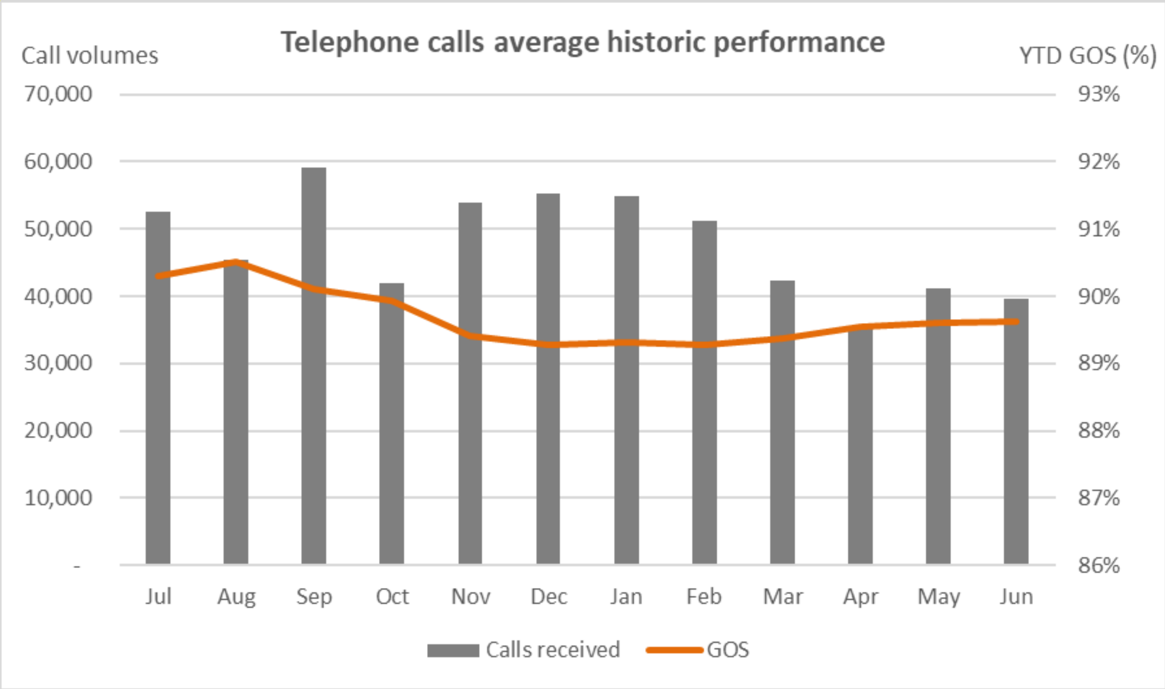
For example, the monthly distribution system total USAIDIn is shown in Figure 1 below. It highlights that the contribution to USAIDIn from unplanned electricity supply interruptions on average is the highest in January (ie just under 16 minutes) and the lowest in April (ie just over 8 minutes).

Figure 1 - Distribution system monthly USAIDIn



The following graph shows the monthly variability in telephone call volumes and the associated impact on the year-to-date Grade of Services[9] (GOS).

[9] The percentage of telephone calls answered within 30 seconds from five published telephone lines



These monthly profiles enable us to monitor and determine if the service standard targets will be achieved on 30 June. It enables the identification of any negative variations in performance during the year that requires investigation to determine the cause(s) (eg systemic or one off type causes). Generally, most variations from the profiles are due to one-off faults or variation due to the number and/or severity of significant weather events that do not result in a MED exclusion.

Operational managers and their teams are tasked with monitoring service standard performance on a daily/weekly basis and must report monthly to the Executive Leadership Team[10](ELT). Any negative deviations from the service standards profiles are highlighted for further investigation and rectification where the cause is systemic or being addressed. Reliability performance is monitored at an individual feeder level, to identify poor reliability and correct it to previous historic levels. Any customer enquiries or complaints about service standard performance are fully investigated to determine if cost effective actions can be taken to improve the performance seen by customers. Further, we will initiate service improvements where the benefit to customers exceeds the costs.

6.4 Evaluating and correcting poor service performance

As highlighted above, SA Power Networks investigates any negative deviation from the monthly service standard performance profiles to determine the cause(s). Once the cause is found, potential options are considered for addressing the performance decline. Once the option is selected, remedial actions are implemented which may require redesign of infrastructure and/or take several months or more to implement. Where it involves a systemic or age related deterioration with a class of asset, a program to replace all those assets over several years may be instigated.

If the cause is potentially associated with a systemic equipment component failure, then other similar failures are investigated to determine if we need to monitor this type of equipment more closely or to develop a programme to replace that equipment across the distribution system.

[10] The Executive Leadership Team includes the Chief Executive Officer and all General Managers.

Operational personnel monitor the performance of individual feeders to ensure that there has not been a gradual decline in the historic performance. Where historic performance is declining, the causes of interruptions are investigated to determine what improvements can be implemented to return the feeders performance to historic levels.

SA Power Networks has established its SPS Committee (see Section 3.6.g) to monitor the performance of the four feeder categories, identify emerging systemic issues and monitor improvement projects and programmes to remedy those systemic issues. The committee meets monthly to monitor these matters.

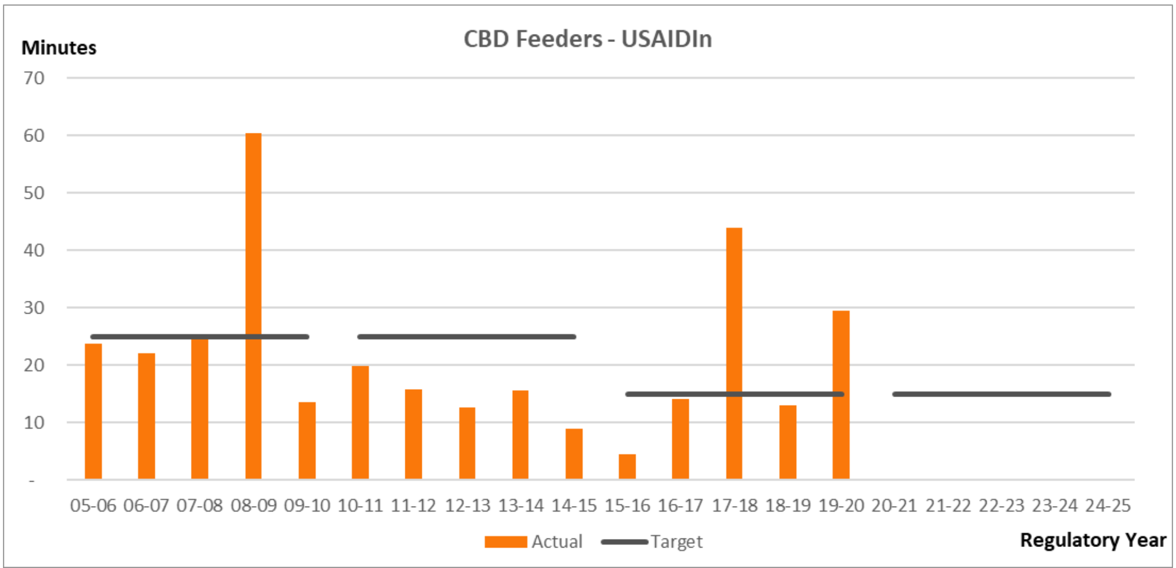
7. Historic Performance

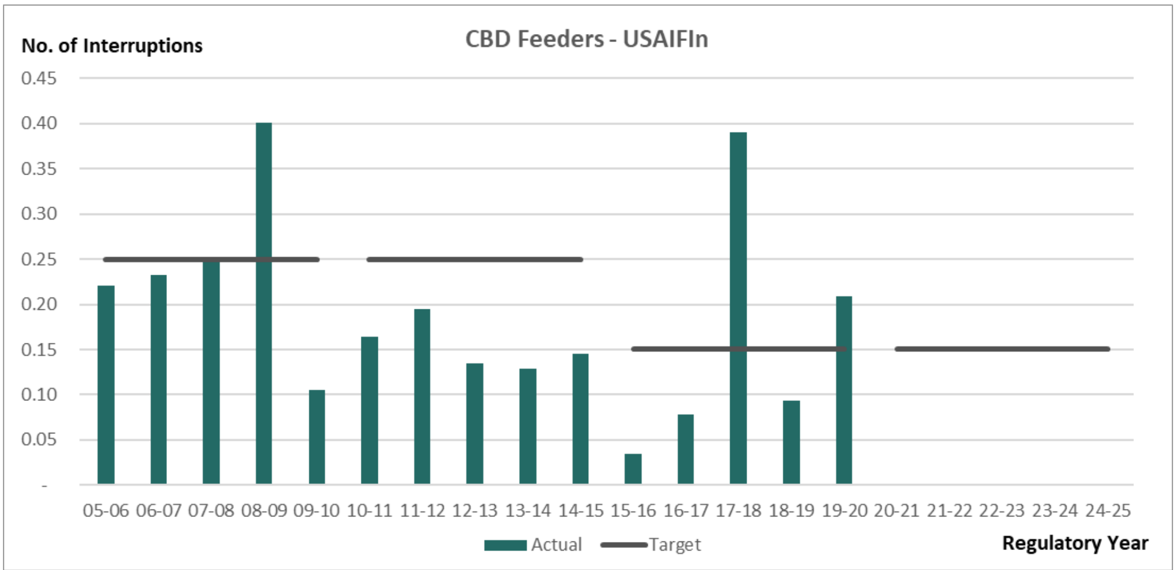
7.1 Reliability

The following details the historic reliability performance of each of the feeder categories since 1 July 2005 until 30 June 2020. The performance is based on the increase in the number of CBD feeders due to the change in the CBD boundary that applies from 1 July 2020.

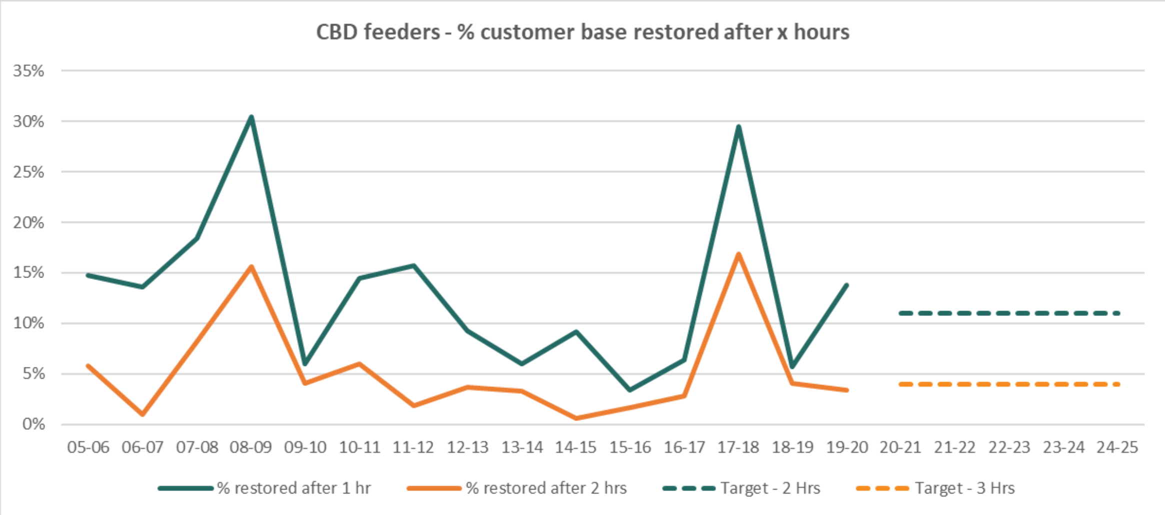
7.2 New CBD feeder category – historic performance

The graphs below demonstrate that normally both the CBD Feeders' USAIDIn and USAIFIn are better than the service standard target. Also it highlights that the CBD performance targets significantly reduced from 2015.



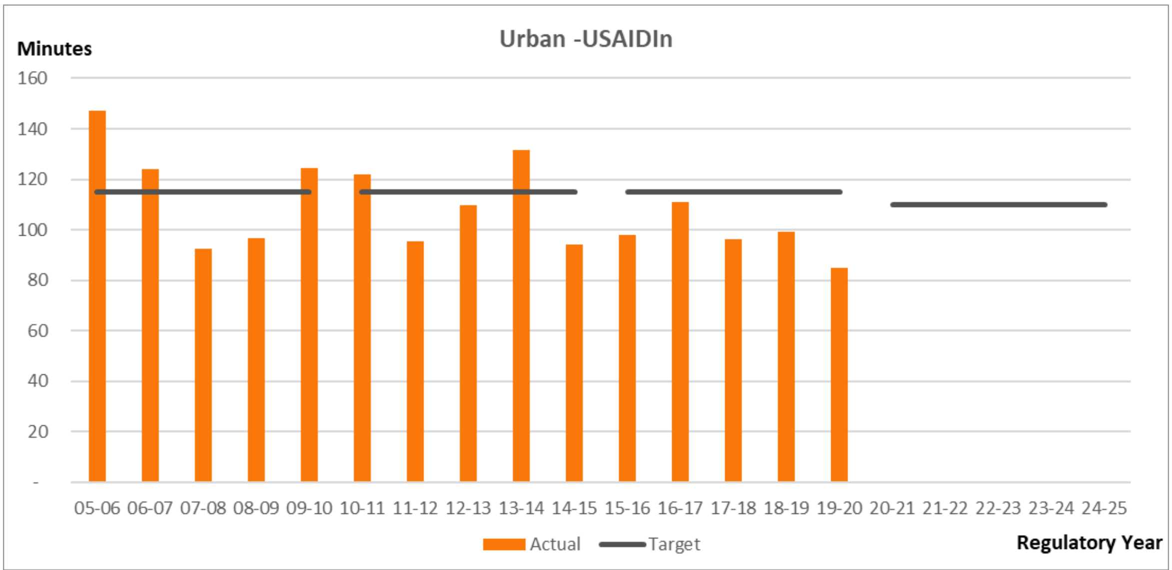


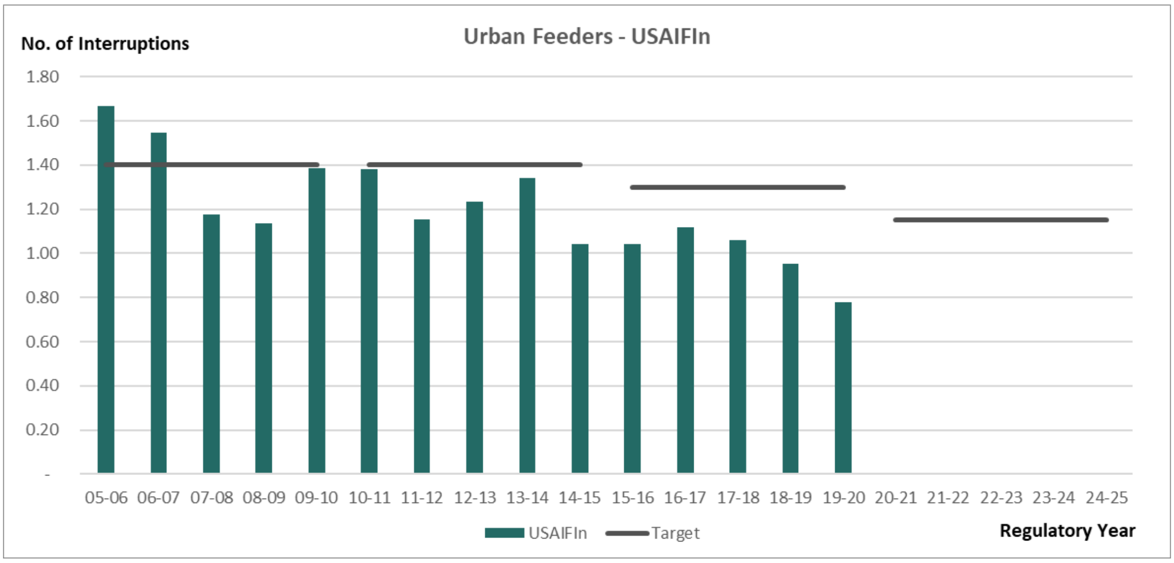
Two restoration of supply service standards have been introduced for the 2020-2025 Regulatory Control Period. The graph below shows considerable annual variation in both measures.



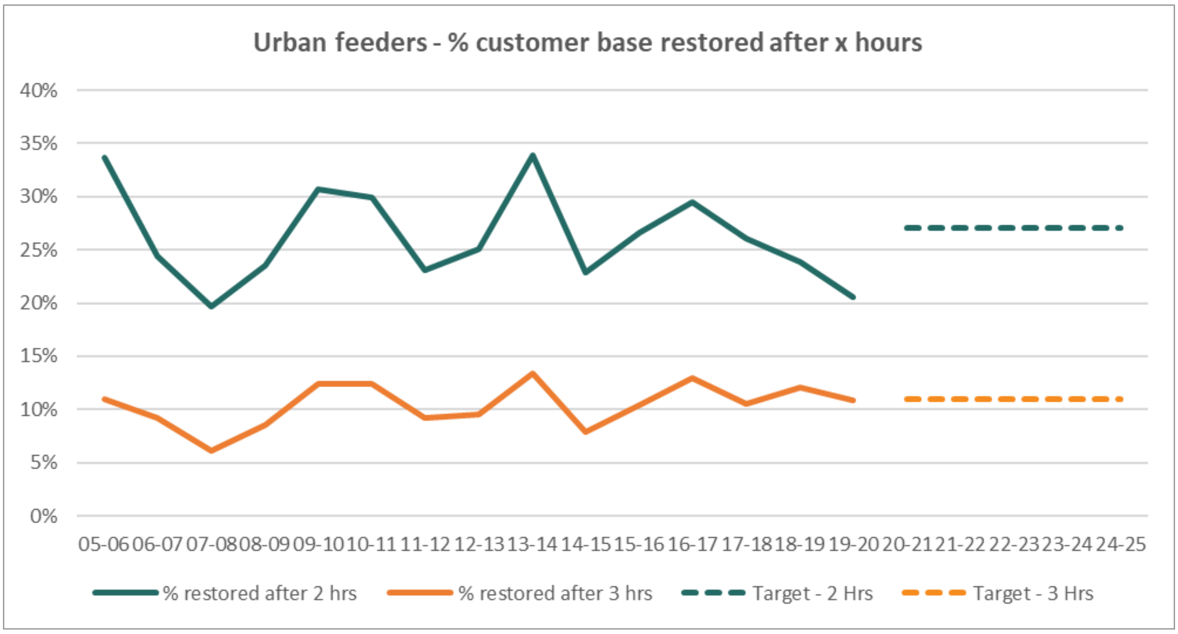
7.2.a *Urban feeder category historic performance*

The graphs below demonstrate that normally both the Urban Feeders' USAIDIn and USAIFIn are better than the service standard target. There has been an overall improvement in USAIDIn and USAIFIn for feeders categorised as Urban.



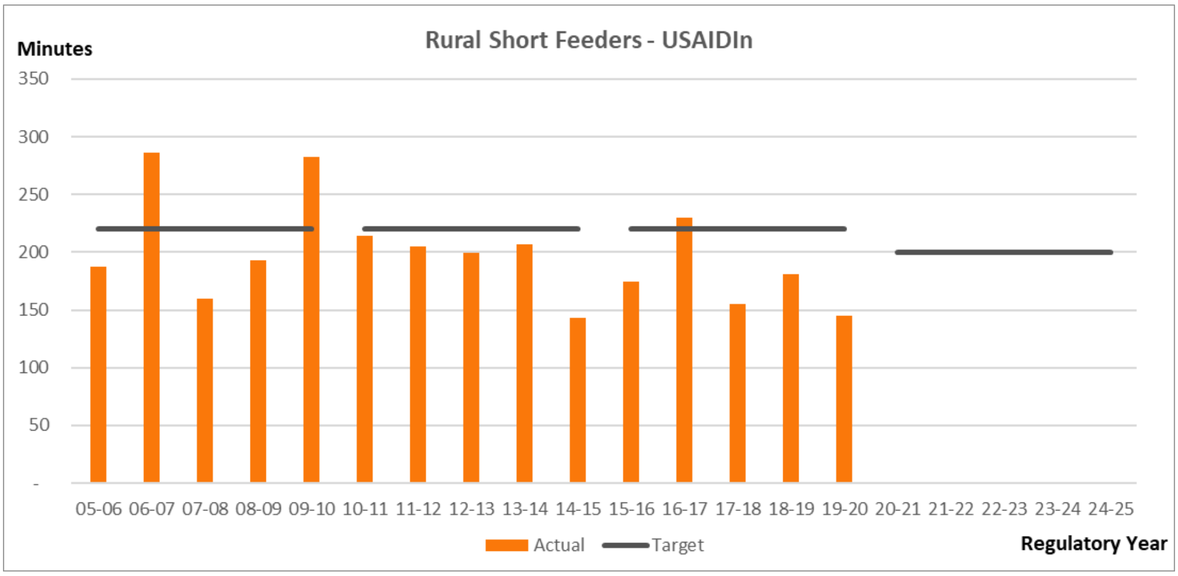


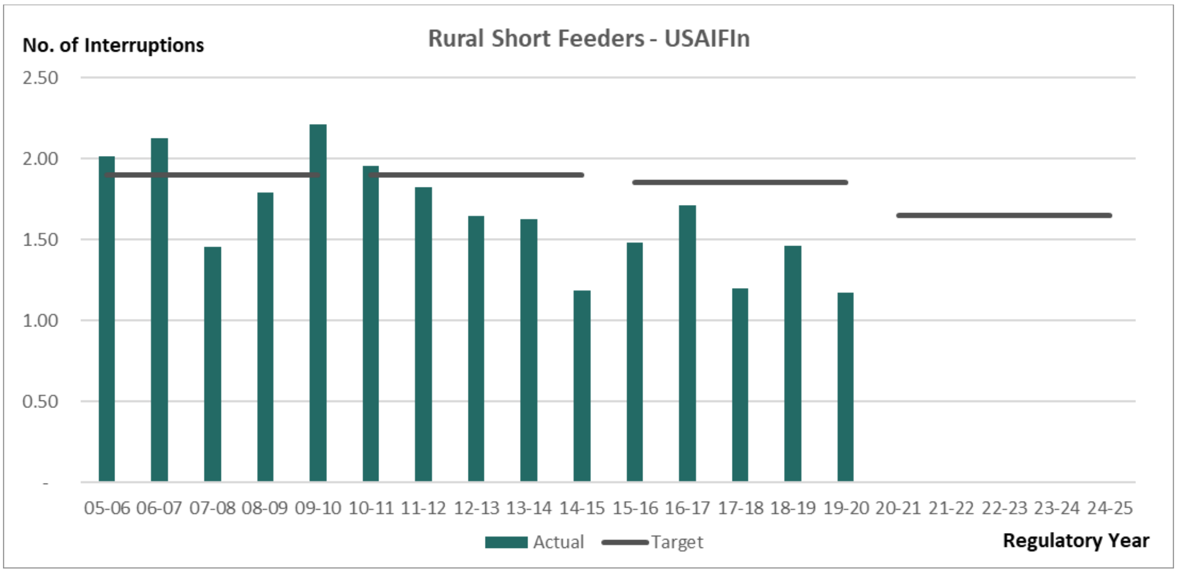
Two restoration of supply service standards have been introduced for the 2020-2025 Regulatory Control Period. The graph below shows greater annual variation in percentage of customers who experience an outage longer than 2 hours when compared to 3 hours.



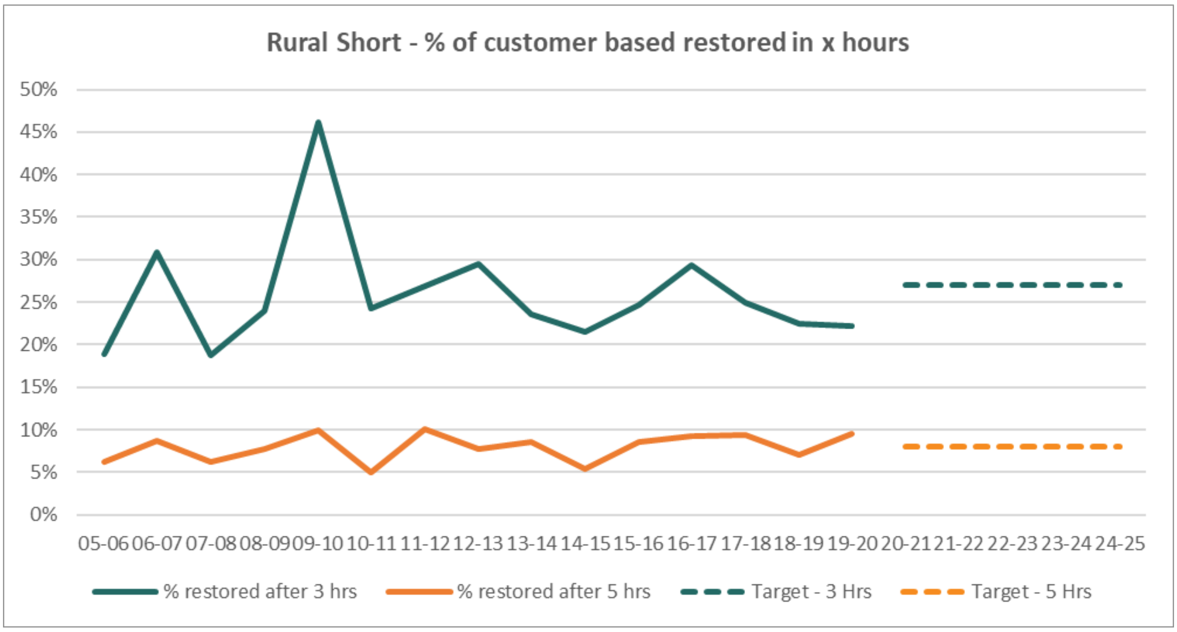
7.2.b Rural Short (RS) feeder category – historic performance

The graphs below demonstrate that normally both the Rural Short Feeders' USAIDIn and USAIFIn are better than the service standard target. There has been an overall improvement in USAIDIn and USAIFIn for feeders categorised as Rural Short.



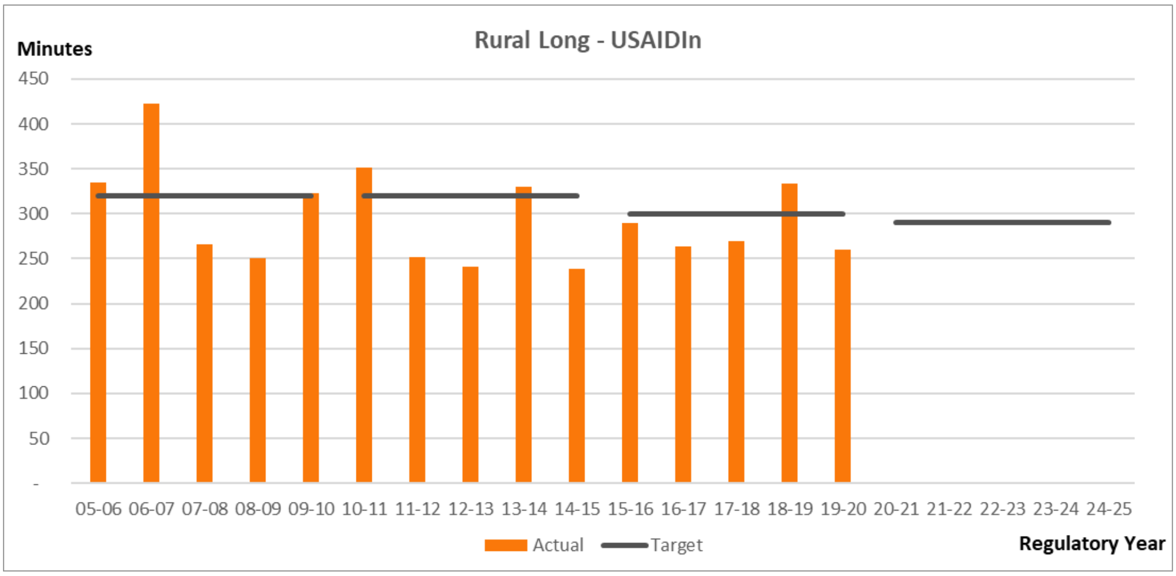


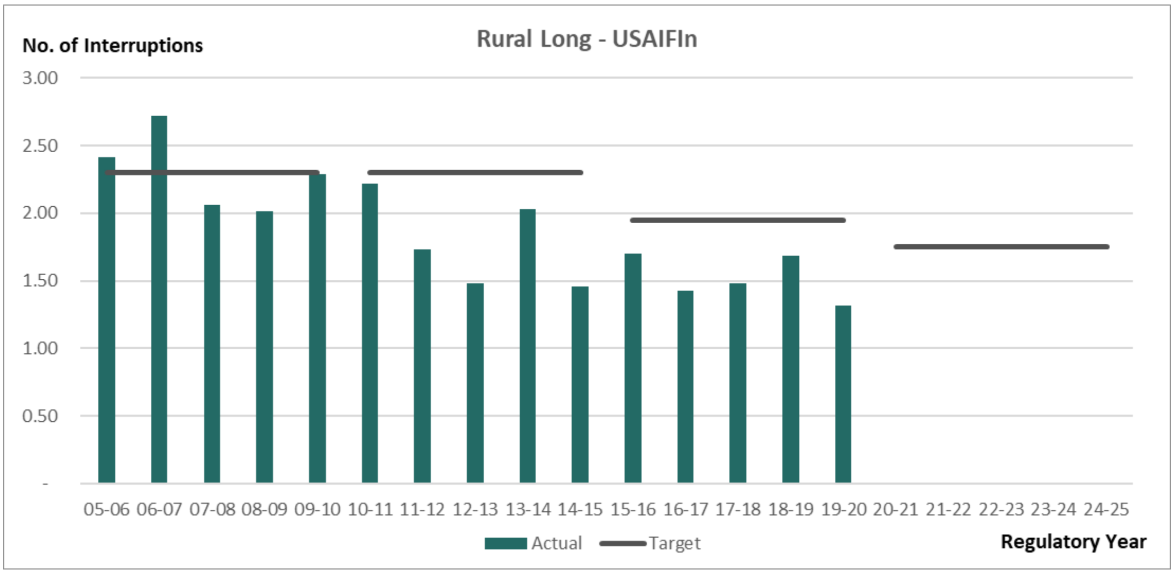
Two restoration of supply service standards have been introduced for the 2020-2025 Regulatory Control Period. The graph below shows greater annual variation in percentage of customers who experience an outage longer than 3 hours when compared to 5 hours.


Rural Short - % of customer based restored in x hours
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
05-06 06-07 07-08 08-09 09-10 10-11 11-12 12-13 13-14 14-15 15-16 16-17 17-18 18-19 19-20 20-21 21-22 22-23 23-24 24-25
% restored after 3 hrs
% restored after 5 hrs
Target - 3 Hrs
Target - 5 Hrs

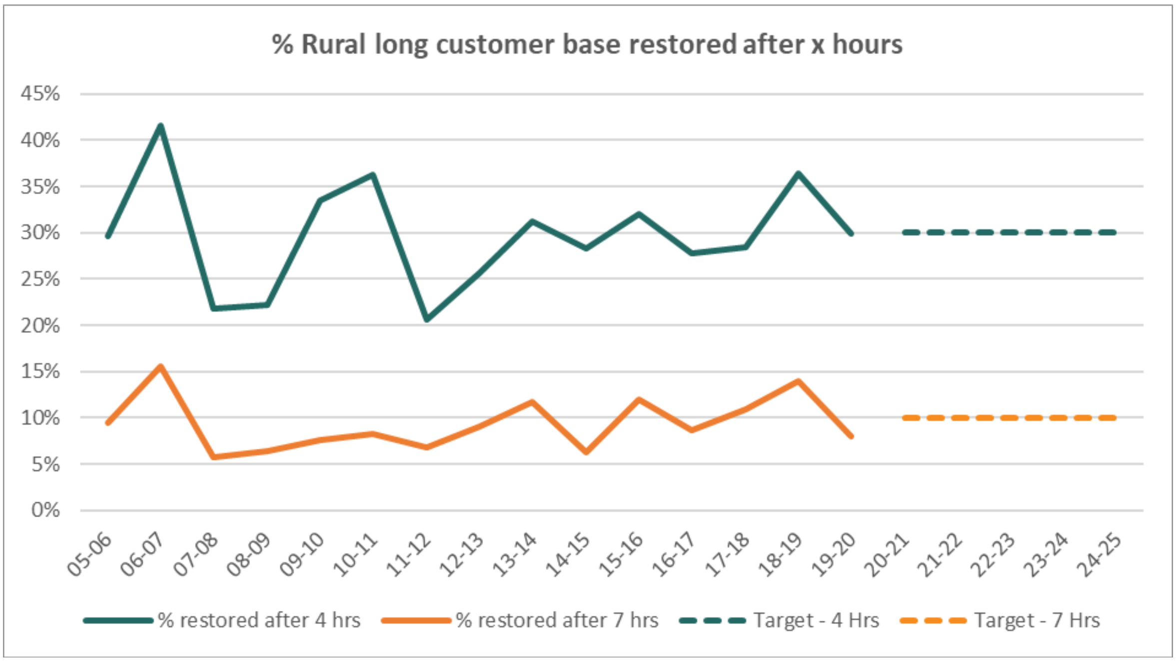
7.2.c Rural Long feeder category — historic performance

The graphs below demonstrate that normally both the Rural Long Feeders' USAIDIn and USAIFIn are better than the service standard target. There has been an overall improvement in USAIDIn and USAIFIn for feeders categorised as Rural Long.





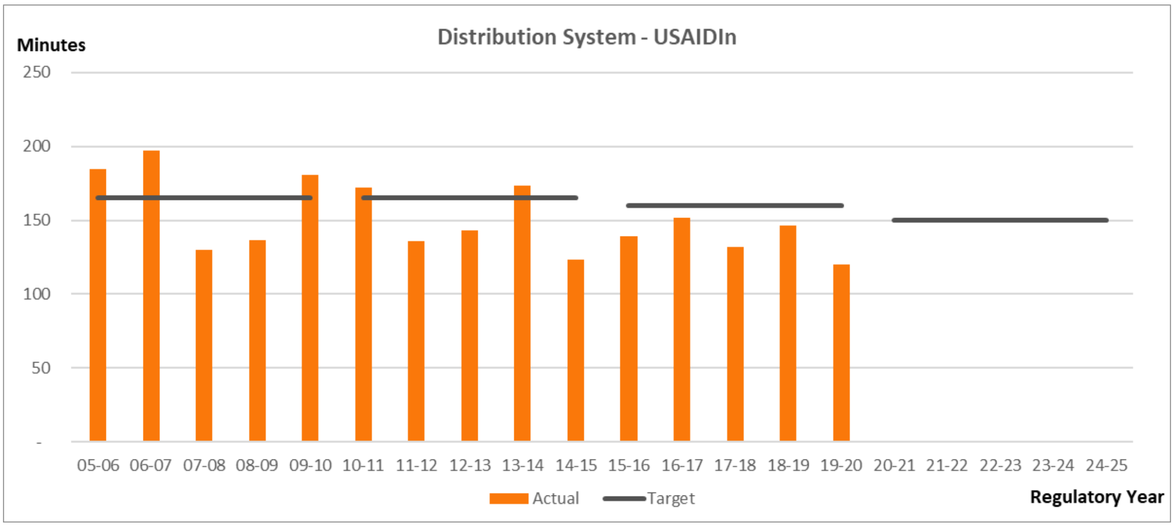
Two restoration of supply service standards have been introduced for the 2020-2025 Regulatory Control Period. The graph below shows greater annual variation in percentage of customers who experience an outage longer than 4 hours when compared to 7 hours.

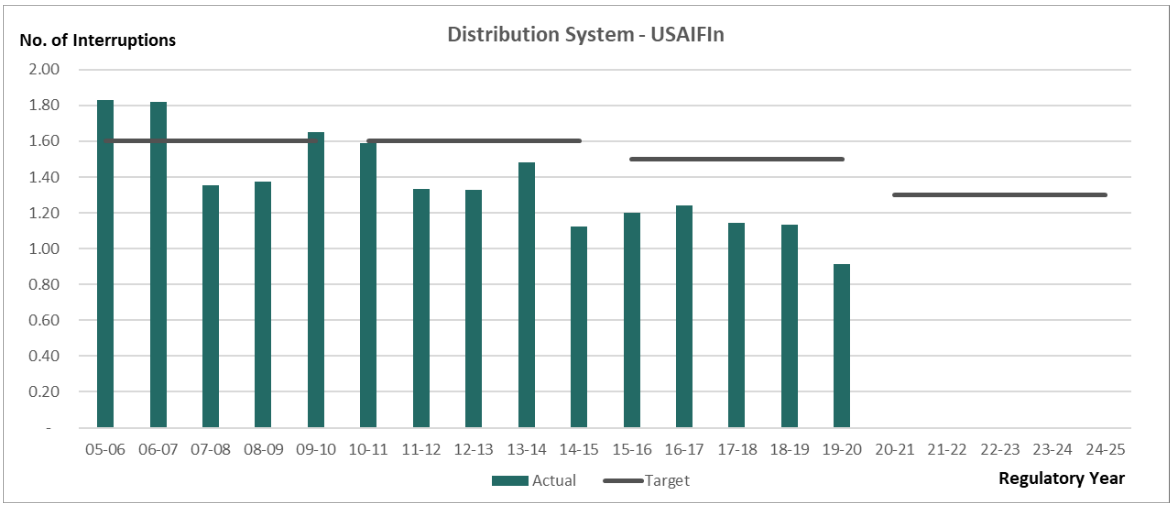


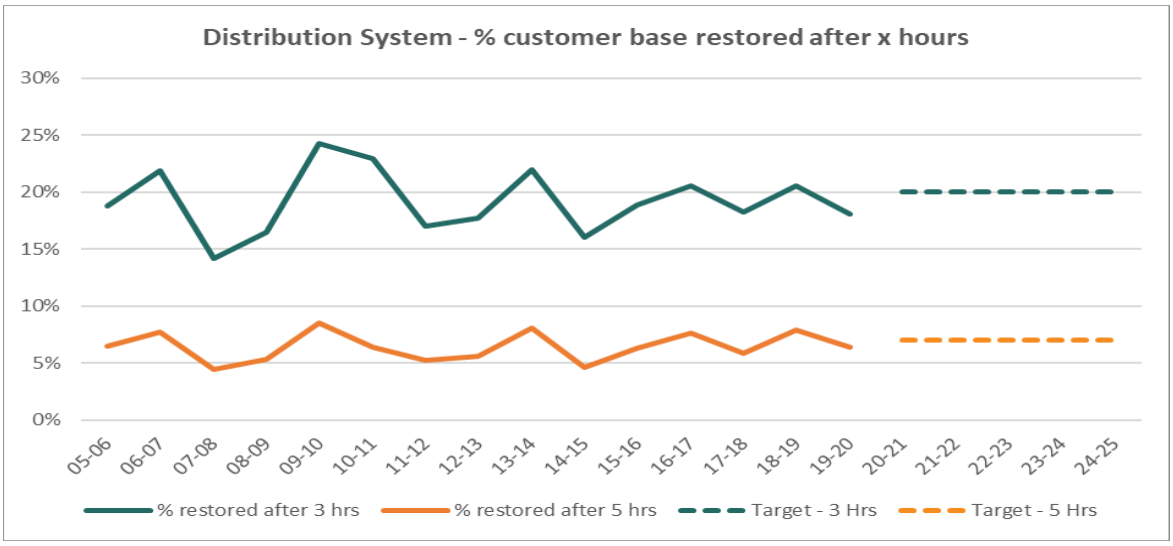
% Rural long customer base restored after x hours
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
05-06
06-07
07-08
08-09
09-10
10-11
11-12
12-13
13-14
14-15
15-16
16-17
17-18
18-19
19-20
20-21
21-22
22-23
23-24
24-25
% restored after 4 hrs
% restored after 7 hrs
Target - 4 Hrs
Target - 7 Hrs

7.2.d Distribution System – Historic performance

There are no reliability service standards established for the overall distribution system, but the following graphs show the historic performance using the same measures as for the four feeder categories and show equivalent targets.



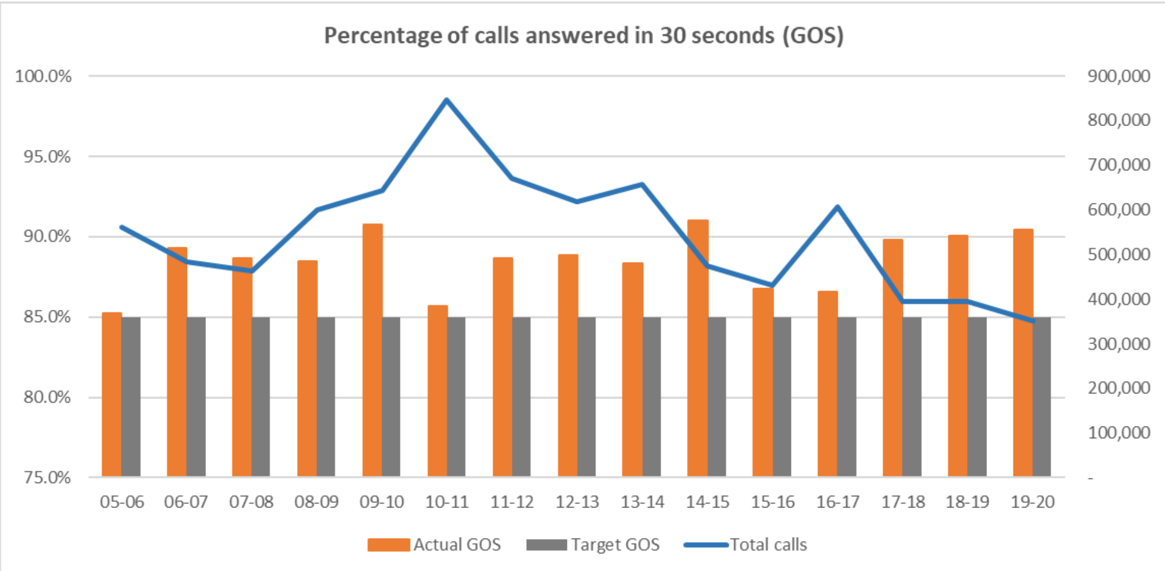




7.3 Customer Service performance

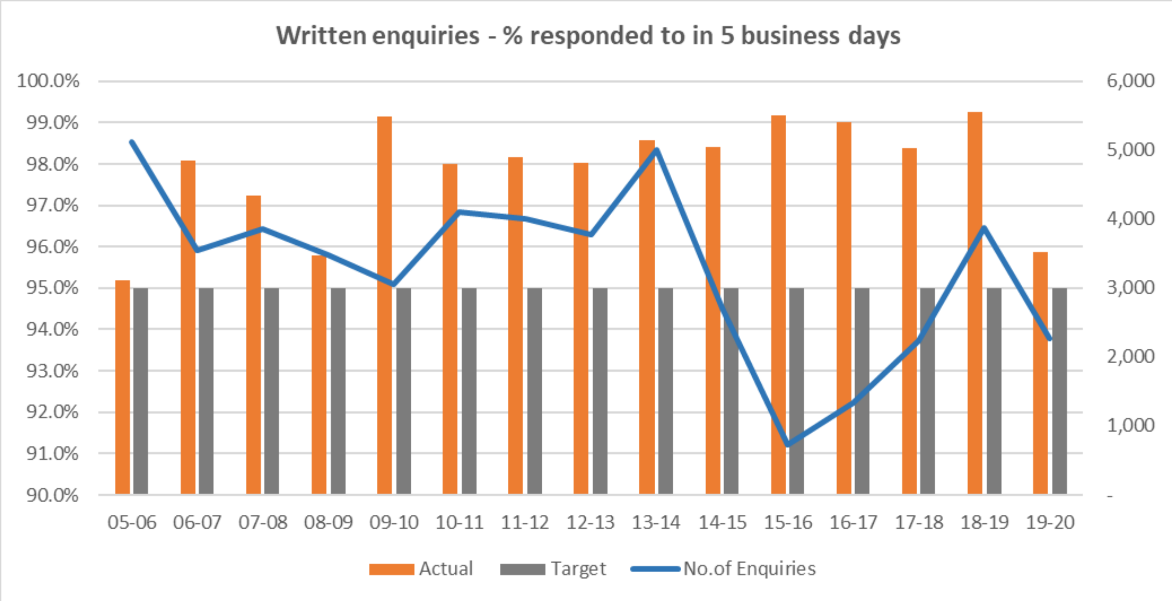
7.3.a Time to response to telephone calls

The graph below demonstrates that we have achieved the telephone response service standard target every year for the last 15 years.



7.3.b Time to response to written enquiries

The graph below demonstrates that we have achieved the responding to written enquiries service standard target every year for the last 15 years.



7.4 Guaranteed Service Level (GSL) Payments

SA Power Networks makes all GSL payments to eligible customers within the required timeframe where we have the necessary information (eg customer's name and postal address) to make that payment.

7.4.a Reliability GSL payments

We typically make about 98% of reliability GSL payments within the require timeframe. The reasons for not making all reliability GSL payments within the required timeframe are due to:

1. the 'customer' to 'asset' link in our systems is not 100% accurate which means that all eligible customers are not identified automatically; and/or
2. some SA Power Networks' interruptions records are inaccurate (eg our systems record that a customer experienced two interruptions, but the customer only experienced a single longer duration interruption).

Where a customer enquires about their reliability GSL payment, we investigate to determine whether our interruption records are correct for that customer and if they are incorrect then our interruption records are amended and all eligible customers who are then eligible will receive the appropriate GSL payment or a top up payment.

SA Power Networks has implemented an Advanced Distribution Management System (ADMS) and is implementing a new Outage Management System (OMS) to replace the OMS implemented in 2005. The two systems enable field crews to see both high voltage and low voltage network models of the distribution system simultaneously, on their mobile device (ToughPad). The ADMS high voltage network model will be updated in near real time as changes in configuration of the network will be updated very quickly (typically within 15 minutes) while the OMS will retain a static model of the low voltage network reflecting normal operating conditions. These models will improve the accuracy of our interruption records and the linkage between customer and the network, which is expected to reduce, but not eliminate, the late payment of some reliability GSLs.

We currently see the only way to ensure that we pay all reliability GSLs to eligible customers within the require timeframe is to install devices in each customer's premises that record unplanned interruption events. This would provide accurate interruption records for each customer to determine their eligibility for a reliability GSL payment. However, this would be very costly and not justified, given the 2% non-compliance rate. A more efficient approach would be to leverage 'smart meter' functionality as new and replacement meters are progressively installed by retailers. Some smart meters can record these unplanned interruption events, but this function is not included in the required minimum specification for smart meters specified in the National Electricity Rules, so this outage information may not be available from most smart meters at this time.

SA Power Networks will continue to explore cost efficient methods to improve the accuracy of our unplanned interruption records and the linkage between our customers and our network. We are proposing to use smart meters to provide other information (eg voltage data) to improve the accuracy of our low voltage network model which will significantly improve the accuracy of our interruption records and our linkage between customers and the network. Over time this will further improve our level of GSL payment compliance.

7.4.b Connection of new supply addresses

SA Power Networks connects around 11,000 new premises annually, with around 98% completed as agreed with the customers or within 6 business days of the preconditions to connection being met. Where a customer is not connected as required a GSL payment is made to the customer. We make around 210 payments annually to customers for a late connection.

7.4.c Repair of streetlight outs (SLO)

SA Power Networks typically repairs 95% of reported failed streetlights within the prescribed timeframe (eg 5 business days for Metropolitan Areas). It makes SLO GSL payments to the first person who reported the SLO where we do not repair the light within the prescribed timeframes. We typically make about 1,500 SLO GSL payments annually, with the majority of these payments due to factors beyond our reasonable control (eg underground cable fault, council vegetation preventing us from accessing the light and do not have permission to clear the vegetation, customers incorrectly reporting working streetlights, consuming resources).

7.5 Reconnection after disconnection

SA Power Networks receives more than 100,000 reconnection of electricity supply requests annually. SA Power Networks typically completes all reconnection requests within the timeframes specified in the EDC. There have been no reconnections outside the EDC specified timeframes in the last few years.