



Monitoring, evaluation, and compliance strategy

June 2026

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Document Control

Version	Date	Notes
1	June 2021	First version of the MECS
2	June 2022	It is substantially the same as we published last year, with updates only in Section 3.6e (our ‘Value and visibility’ approach to maintaining assets) Section 6.5 (Reliability Performance focus areas) and section 7 (to include actual 2020/21 performance outcomes)
3	June 2023	Update to Sections 3.1 (distribution system asset breakdown) and 7 (includes 2021-22 performance), new Sections 3.2 Safety Reliability Maintenance and Technical Management Plan (SRMTMP), 6.5.e Rural Network Restoration Performance and 3.7 Reliability Management.
4	June 2024	2024 Update
5	June 2025	2025 Update. Includes EDC 14.1 updates.
6	June 2026	2025 Update

1. Introduction

About SA Power Networks

SA Power Networks distributes electricity to more than 950,000 homes and businesses across South Australia and is responsible for maintaining a safe, reliable and efficient supply of electricity. We also play a critical role in enabling customers to connect and export renewable energy to the grid from hundreds of thousands of **consumer energy resources (CER)**, including rooftop solar, batteries and electric vehicles.

SA Power Networks manages the distribution network that supplies electricity from the high voltage transmission system to customers. Our infrastructure and assets include distribution substations, transformers, circuit breakers and switchgear, overhead powerlines, power poles including Stobie poles, and underground cables.

The network spans more than 178,000 km², with a total route length exceeding 95,000 km and an estimated replacement value of more than \$65 billion. This extensive infrastructure enables SA Power Networks to supply electricity to almost all parts of the state.

SA Power Networks provides a fully managed electricity distribution service, including:

- monitoring the network 24/7 to support safety and reliability;
- connecting new customers and supporting growing demand for load and export services;
- managing safety risks and addressing reliability and quality of supply issues;
- restoring power during outages and keeping customers informed; and
- complying with relevant Acts, regulations and service standards.

Adapting to Change and Meeting Challenges

South Australia's energy transition is accelerating, driven by technological change, policy settings and evolving customer expectations. The state is progressing towards net 100 per cent renewable electricity generation by 2027. High per capita uptake of rooftop solar is increasing pressure on distribution network capacity, and SA Power Networks is adapting its operations and planning to enable greater integration of CER as the transition continues.

SA Power Networks has a strong track record in safety, reliability and cost efficiency, and is recognised as a leader in energy innovation. At the same time, it is operating in an increasingly complex environment shaped by ageing infrastructure, climate change and the pace of the energy transition. Rising bushfire risk and more frequent extreme weather events are reinforcing the need for a more resilient network and targeted investment to support long-term safety, reliability and sustainability.

The network is predominantly overhead and is therefore vulnerable to weather-related risks such as bushfire, high winds and heatwaves. At the same time, rapid growth in rooftop solar and other CER is increasing reverse power flows during mild, sunny conditions, creating operational challenges and, in some areas, exceeding local network capacity, particularly on the low-voltage network. In response, SA Power Networks is continuing to refine its strategies and planning approaches to manage these emerging risks and opportunities while maintaining network performance and resilience over the long term.

Our **Monitoring, Evaluation, and Compliance Strategy (MECS)** sets out how we monitor and evaluate our performance and maintain compliance with the customer service and reliability standards set out in the **Electricity Distribution Code (EDC)**¹.

¹ Essential Services Commission of South Australia: Electricity Distribution Code EDC14.1

Customers and Stakeholders

Our customers and stakeholders are diverse, geographically dispersed and evolving. SA Power Networks serves almost the entire population of South Australia and, as the state grows, so does the number of customers relying on the distribution network. Technological change is transforming the energy sector, and customer expectations are changing just as quickly.

Customers expect:

1. a safe and reliable electricity supply;
2. high-quality service;
3. support for the clean energy transition; and
4. affordable prices, with a focus on equity.

Customers also expect better information about outages and restoration times, as well as greater transparency around costs. SA Power Networks is committed to meeting these expectations while enabling customers to use the network in new ways, including as both consumers and exporters of electricity.

Purpose of this Document

SA Power Networks is required by its electricity distribution licence to comply with the South Australian EDC. Clause 2.6 of the EDC requires SA Power Networks to prepare an annual MECS in accordance with the **Essential Services Commission of South Australia's (ESCoSAs)** Electricity Industry Guideline No. 1. The guideline requires the MECS to explain how SA Power Networks plans to meet the service standards defined in clauses 2.1 to 2.4 of the EDC. These standards include:

- customer service measures under clause 2.1;
- reliability measures under clause 2.2;
- **Guaranteed Service Level (GSL)** payments under clause 2.3; and
- reconnection after disconnection under clause 2.4.

This document outlines SA Power Networks' approach to achieving these standards and is structured as follows:

- **Section 1:** Introduction
- **Section 2:** service standard obligations
- **Section 3:** Monitoring, evaluation and compliance strategy
- **Section 4:** Environmental and external factors
- **Section 5:** Current issues impacting network reliability
- **Section 6:** Emerging trends impacting network reliability
- **Section 7:** Use of best endeavours
- **Appendix A:** Our risk management framework

This document complements the public version of SA Power Networks' Annual Public Reliability Performance Report², which sets out performance against prescribed service standards over the past regulatory year, and the **Distribution Annual Planning Report (DAPR)**³, which summarises proposed works over the forward five-year planning period.

² [Annual Public Reliability Performance Report](#)

³ [Distribution Annual Planning Report \(sapowernetworks.com.au\)](http://sapowernetworks.com.au)

2. Service standard obligations

SA Power Networks is required under its electricity distribution licence to comply with the service standards set out in the EDC. The EDC requires SA Power Networks to use best endeavours to achieve the applicable service standard targets for each financial year ending 30 June.

Clause 1.5.1 of the EDC defines best endeavours as acting in good faith and using all reasonable efforts, skill and resources. This means SA Power Networks may still comply with a service standard obligation even where a target is not achieved, provided it can demonstrate that it used best endeavours in seeking to achieve that target.

ESCoSA periodically reviews the EDC service standards, typically in the lead-up to the **Australian Energy Regulator's (AER's)** distribution determination for SA Power Networks. The service standard measures and targets for the 2025–30 period took effect on 1 July 2025.

Under its distribution licence, SA Power Networks must also provide information to ESCoSA and the **Office of the Technical Regulator (OTR)** in accordance with ESCoSA's Electricity Industry Guideline No. 1⁴.

3. Monitoring, evaluation and compliance strategy

SA Power Networks seeks to achieve the service standards specified in clauses 2.1 to 2.4 of the EDC for each financial year ending 30 June.

SA Power Networks has implemented, and continues to refine, its procedures and practices for monitoring performance against those standards and evaluating compliance. This includes taking action to address any sustained decline in performance, so as to maintain historical performance levels, and pursuing improvements in historical performance where the benefits to customers outweigh the associated costs. In addition, where reliability declines on a feeder or part of the network, SA Power Networks implements corrective measures aimed at restoring reliability to its previous level.

The following sections summarise the four categories of service standards and associated targets, where specified, for the 2025–30 **Regulatory Control Period (RCP)** (1 July 2025 to 30 June 2030). They also outline the strategies SA Power Networks has in place to monitor performance and evaluate compliance against those standards.

3.1 Board commitment to compliance

SA Power Networks' Board Compliance Policy sets out the organisation's commitment to conducting its business activities in compliance with all relevant legal, regulatory and contractual obligations, as well as applicable internal policies, directives, procedures and guidelines. The Policy states:

SA Power Networks will conduct its business activities in compliance with all relevant legal, regulatory and contractual obligations as well as policies, directives, procedures and guidelines.

The Policy establishes a framework designed to support compliance and minimise the risk of non-compliance. This is achieved through a structured compliance system that includes the following key elements:

- identification of obligations;
- designation of responsibility for compliance with those obligations;

⁴ ESCoSA, Electricity Regulatory Information – Requirements – Distribution, Electricity Industry Guideline 1 Ver G1/14

- implementation of processes, procedures and other controls, where applicable, to support compliance;
- provision of information and education about those obligations;
- promotion of the importance of compliance;
- monitoring and assessment of compliance;
- reporting on compliance and non-compliance; and
- management oversight and independent review of the compliance system by the Head of Audit, Risk and Insurance.

This systematic approach assists SA Power Networks to mitigate the risks associated with non-compliance, including financial loss, regulatory or legislative penalties, and reputational impacts. It also supports a culture of compliance across the business and reinforces SA Power Networks’ commitment to meeting its obligations and maintaining effective relationships with key stakeholders.

3.2 Customer service measures

There are two customer service standards defined in the EDC relating to communication with our customers:

- Time to respond to telephone calls; and
- Time to respond to written enquiries.

These standards measure how quickly we respond to customer enquiries by both telephone and written responses.

From 1 July 2028 onwards, SA Power Networks will be required to achieve:

- separate customer service standards for telephone responsiveness and first contact resolution on its general enquiries phone line, and
- separate customer service standards for telephone responsiveness on its builders and contractors phone line and an additional customer service quality measure for builders and contractors.

In March 2026 ESCoSA’s Electricity Industry Guideline No. 1 was updated to include a new reporting template (OP 1.7) for these new service standards. The performance targets will be established based on our performance during the period 1 July 2025 to 30 June 2027 and will be published on ESCoSA’s website prior to 1 July 2028.

3.2.1 Responding to telephone calls

Service standard definition

SA Power Networks is required to use best endeavours to meet the service standard for responding to telephone calls as set out in Table 1 for each year ending 30 June.

Table 1: Customer service measures and targets

Category	Customer service to measure	Target
Customer service – telephone responsiveness	Time to response to telephone calls - all telephone lines	85% within 30 seconds

The EDC defines responding to telephone calls as:

- answering a customer’s telephone call in person, or
- answering a customer’s telephone call after they have used an Interactive Voice Response system to elect to talk to an operator (with monitoring of the call waiting time commencing when the caller

selects the relevant operator option and covers the time from this point until an operator picks up the call to deal with the caller's issue), or

- c) answering a customer's telephone call by providing access to a computer/telephony based interactive service which can process calls by providing information or direct calls to a service officer, but does not include the answering of a call by being placed in an automated queue to wait for any one of the options above.

When responding to telephone calls, SA Power Networks must always use its best endeavours to ensure that all of the information provided, including that which is provided by means of a computer/telephony based interactive service, is current and accurate and that vital information for customers is not omitted.

Our strategy

SA Power Networks aims to optimise call handling processes, manage resources efficiently, and enhance the overall customer experience by answering calls within 30 seconds, in line with service obligations. To support this standard, we use efficient workforce management practices that combine a core team of contact centre agents with additional overflow support when needed.

Real-time monitoring and reporting identify trends and issues as they arise, supported by performance dashboards visible during operating hours. SA Power Networks also supports continuous improvement through training and development on our knowledge management system. Where enquiries cannot be resolved during the initial call, call back and queue management processes are used to support timely follow-up and efficient handling of customer interactions.

Faults and emergency contact centre

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

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, helping to ensure that all faults and emergency calls are handled promptly. SA Power Networks maintains a pool of trained employees who can be deployed to staff the SCC as required. The SCC generally manages inbound calls from the Faults and Emergencies line any may also make outbound calls to Life Support Customers or customers significantly affected during an event to better understand customer impacts and priorities.

How we monitor and evaluate our performance

To support compliance with the telephone call response service standards, we use a range of methods for monitoring our performance. Intraday, daily and monthly reporting is used to identify emerging trends as they arise. Within the contact centre, large displays provide real-time visibility of current day performance for leaders and agents, while dashboard-based applications support daily results for leaders and managers. End of month reporting is also prepared to support broader business reporting, with additional accuracy reviews undertaken as part of that process.

Should a problem with data from our telephony systems be identified, managers are notified and the issue is resolved with vendor support if required.

3.2.2 Responding to written enquiries

Service standard definition

SA Power Networks is required to use best endeavours to meet the service standard for responding to written enquiries as set out in Table 2 for each year ending 30 June.

Table 2: Customer service measures for written enquiries

Category	Customer service to measure	Target
Customer service – written enquiry responsiveness	Time to respond to written enquiries	95% within 5 business days after receipt of the written enquiry

A written enquiry is an enquiry from a customer by the use of:

- Email;
- Fax;
- SA Power Networks’ website;
- Direct messaging on SA Power Networks’ social media channels; or,
- a letter sent by a customer to SA Power Networks, via nominated enquiry channels, requesting information from us and/or making a complaint about an action of SA Power Networks.

A response to such an enquiry means direct or telephone contact or a written response in which we either answer the enquiry or acknowledge receipt of the enquiry and indicate the process and timeline to be followed in dealing with the enquiry.

Our strategy

We have established systematic processes to ensure all emails, social media and other written enquiries are responded to, with the aim of meeting or exceeding the established service standards. Multi-skilled contact centre agents manage these interactions and use queue management techniques to triage and prioritise customer enquiries for efficient handling.

How we monitor and evaluate our performance

Real-time monitoring and dashboards enable SA Power Networks to track workflows and support compliance with this service standard. Daily, weekly, and monthly reporting against the target help to identify trends and supports the ongoing optimisation of processes and systems to improve customer interactions and experience.

3.3 Reliability measures

There are three reliability measures for SA Power Networks’ distribution system:

- **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 supply** — 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.

To measure the distribution system’s performance in a like for like manner, SA Power Networks’ power line feeders are allocated into four categories defined by the EDC, as follows:

- **Central Business District (CBD)** – 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** – 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.

Table 3 below summarises information about each feeder category.

Table 3: EDC feeder category metrics

Feeder	CBD	Urban	Rural Short	Rural Long
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, Southeast, Upper North
% of customers	0.8%	69%	15%	15%
Circuit length of powerline (km)	320	26,500	14,120	49,500
Annual Consumption (GWh)	560	6,600	1,300	1,300

Due to large annual variations in feeder category reliability performance, the reliability service standards include a reporting threshold, which represents the 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 reporting threshold. We note that, the reporting threshold 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.

3.3.1 Network reliability standards

Service standard definition

SA Power Networks must use its best endeavours to achieve the minimum network reliability standards set out in Table 4, during every regulatory year ending 30 June. If SA Power Networks does not meet the applicable reporting threshold, we must report on how we applied *best endeavours* in seeking to achieve the relevant standard.

Table 4: SA Power Networks' minimum reliability service standard targets and reporting thresholds

Measure		CBD	Urban	RS	RL
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

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.

The reliability service standard targets exclude interruptions that occur on a **Major Event Day (MED)**⁵ which normally result from extreme weather events. The normalised reliability targets which exclude MEDs are designated with an ‘n’ (e.g. USAIDIn).

Our strategies

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

- network performance meets the requirements of the **National Electricity Rules (NER)** and the South Australian EDC in relation to system security and performance standards;
- quality of supply is maintained for customers;
- operational risks and hazards are identified and managed;
- electricity infrastructure is secured against unauthorised access; and
- responses to the risks presented by accidents and incidents involving electricity infrastructure are adequate and timely.

Asset inspection and maintenance play a critical role in supporting the ongoing operation and efficiency of South Australia’s electricity distribution network, much of which was constructed in the 1950s, 1960s and 1970s. Regular inspection and maintenance are necessary to support the reliability of the distribution network and reduce the risk of fire starts.

We use a range of strategies to maintain a safe and reliable distribution network. The major activities we undertake include:

- **Network operations** – to efficiently control our distribution network (see Network Operations Centre below);
- **Asset inspection** – to understand the condition of our network;
- **Vegetation management** – to minimise obstructions on our network;
- **Asset maintenance** – to keep assets in good working order;
- **Asset refurbishment** – to extend asset life where feasible;
- **Asset replacement** – to replace assets prudently with minimal disruption to network operations;
- **Network augmentation** – to ensure sufficient capacity to supply customers, this can include implementation of distributed energy resources management strategies; and
- **Reliability programs** – targeted reliability programs such as improving services to those who experience poor reliability, hardening the network against the impacts of severe weather and to address other emerging issues affecting our network. For example, management of insulator pollution.

Our **Safety, reliability, maintenance, and technical management plan (SRMTMP)**⁶ details the management framework, key procedures and associated performance indicators for the safety and technical management of SA Power Networks’ electricity infrastructure throughout its life cycle.

SA Power Network also has a corresponding Asset Management System.

⁵ 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 (i.e. midnight to midnight), this compares to an average for a non-MED of about 0.4 minutes.

⁶ The SRMTMP is annually approved by the Office of the Technical Regulator (SA Government).

Safety, reliability, maintenance, and technical management plan

The Electricity Act 1996 states that a licence issued to the operator of a distribution network must include a condition that the operator prepare and periodically revise a SRMTMP, which deals with matters that are prescribed by regulation.

The operator must also comply with the plan, audit its compliance with the plan and report the results of the audits to the OTR. SA Power Networks' SRMTMP details the management framework used to ensure that the network is operated and maintained in a safe and effective manner. This is supported by a number of manuals covering policies, strategies, operating processes and standards.

The SRMTMP details a management framework which ensures that:

- The electrical system is in a stable condition at all times;
- Quality of supply is maintained to customers;
- Operational risks and hazards are identified and managed;
- The electricity infrastructure is secured to prevent unauthorised access; and
- Responses to the risks presented by accidents and incidents involving electricity infrastructure are adequate and timely.

Each year, SA Power Networks engages an independent third-party auditor to review our compliance with the SRMTMP, with results of the audit reported to the OTR.

The annual assessment provide assurance that:

- Policies and Directives referred to in the SRMTMP are available, accessible, current and complied with;
- Documents referred to in the SRMTMP are complete, accessible and current;
- Records required by the SRMTMP are complete, accurate and securely controlled;
- Management controls detailed in the SRMTMP are effectively implemented; and
- Roles and responsibilities detailed in the SRMTMP are understood and effectively implemented.

As part of the 2025 audit, the auditor reported that SA Power Networks achieved overarching compliance with the OTR's requirements across all the key criteria outlined above, with no non-compliances noted.

Asset Management Approach

SA Power Networks' Asset Management is guided by our Asset Management 2035 Vision, which aligns with our corporate Strategic Directions 2035. Our focus is on delivering outcomes that reflect the needs and values of our customers and stakeholders. By employing evidence-based decision-making, we optimise work planning and delivery to ensure sustainable, cost-efficient network investments and performance.

A key feature of our approach is a decision-making process based on return on investment. This process evaluates both the monetised risks addressed by an asset intervention and the additional benefits it generates. This enables us to select optimal maintenance and replacement strategies for each asset sub-class, ensuring technical feasibility, economic viability, and alignment with our risk strategy, all while maximising customer value.

Asset Management Strategies

Our asset management strategies recognise the diverse characteristics of assets within the network. By considering asset groups, classes, and sub-classes, we balance capital and operational expenditure to optimise performance and customer service delivery.

Asset management brings together management, financial, economic, engineering, and other disciplines to provide the required level of service in the most cost-effective manner. This includes applying risk management techniques across the entire asset lifecycle - from procurement and operation to maintenance, condition monitoring, and eventual disposal or replacement - while ensuring compliance with legal and regulatory obligations.

Our goal is to manage the electrical network and associated systems to meet customer service needs, fulfil license and regulatory obligations, and provide a safe environment for employees, contractors, and the community. By employing good industry practices, we ensure the long-term sustainable performance and condition of our assets while delivering optimal returns to shareholders.

SA Power Networks is committed to continually improving its asset management practices and systems. A significant advancement has been the transition from a replace-on-fail approach to a replace-based-on-value approach. This shift relies on robust asset condition data and advanced analytical techniques to assess the risks of asset failure and support prudent lifecycle decisions.

To enhance asset condition reporting, we deployed the BlueWorx mobility tool in 2022, replacing the legacy SAP Work Manager. BlueWorx enables Asset Inspectors to record defects and capture detailed asset condition data, which feeds into SAP, a key data source for the Operational Risk Cost Model (ORCM). The ORCM, supported by our Value Framework, uses a sophisticated algorithm to prioritise risk mitigation efforts and direct resources to the most critical areas.

The enhanced **Risk Cost Model (RCM)** was developed to assess the risks posed by network assets. This model aligns with AER guidelines on network asset risk and was instrumental in determining funding requirements for the 2025–2030 regulatory period.

Inspection and maintenance policy

Under its Inspection and Maintenance Policy, SA Power Networks has developed strategies and procedures for the inspection and maintenance of its power system assets (substations, sub-transmission and distribution powerlines) to ensure the present and future performance of those assets.

To ensure clarity of information for the intended user level in the organisation, a document hierarchy has been developed for maintenance management:

- The Inspection and Maintenance Policy is embodied within SA Power Networks' Network Directive (ND) M1;
- In accordance with the requirements of ND M1, a detailed maintenance strategy has been developed for each asset type. These strategies are detailed in the Network Maintenance Manual; and
- The Asset Inspectors implement the inspection strategies under the provisions of the:
 - Technical Standard – Substation Inspection Manual; and
 - Technical Standard – Line Inspection Manual.

These Standards specify processes for the identification, ranking and rectification of defects before they develop into faults. They detail the inspection and patrol requirements, the codes for different types of defects and the guidelines for allocation of severity to those defects.

While the recommended severity ratings in these Standards are informed by operational experience, supply interruption and fire start data, the actual severities are assigned by trained and accredited Asset Inspectors according to the specific conditions observed at the time of inspection.

At SA Power Networks, the Asset Condition & Performance Team is responsible for inspecting distribution assets, while the Asset Engineering Team oversees their maintenance and management. Asset performance is continuously reviewed to ensure that strategies effectively optimise performance, manage risk, and control costs associated with maintaining distribution assets.

To assist in the development of a rapid response to asset performance issues, the **Service Performance Scheme (SPS)** Steering Committee and **Asset Performance Review Committee (APRC)** monitor plant performance. These Committees meet regularly and ensure that strategies are developed to avoid recurring failures.

Network maintenance manual

The Network Maintenance Manual details the strategies which govern SA Power Networks' network maintenance practices. It contains the management philosophy, directives, maintenance regimes and responsibilities for SA Power Networks' distribution equipment. A range of maintenance strategies are employed, depending on the asset type, failure modes and criticality of the asset. For each class of asset, the manual defines the maintenance strategy to be adopted in terms of content and frequency of routine inspections, servicing, spares, strategies, and asset condition reports to be kept.

Technical Standards – Substation maintenance manual

The frequency and standards to which substation assets are maintained are also specified in the Network Maintenance Manual. Substation asset categories include circuit breakers, transformers, **Direct Current (DC)** Systems and Protection systems. Maintenance strategies vary by asset type, but generally include regular inspection, condition monitoring and invasive maintenance on a cyclic and as-needs basis for defect repair.

Technical Standards – Line inspection manual

The Line Inspection Manual details SA Power Networks' inspection procedures and provides examples of defects commonly associated with powerlines, insulators, support structures, service equipment and switchgear. These defect examples are used as a guide for Asset Inspectors to determine the appropriate defect priority and to ensure consistency of application of priority classification between Inspectors. The Line Inspection Manual incorporates inspection based on condition severity in line with the Operational Risk Cost Model and SA Power Network's Value framework.

Asset inspections

Asset inspections and condition monitoring are designed to identify defects or issues before assets fail. This process helps determine whether maintenance, renewal, or replacement is required.

We use a variety of techniques to assess asset condition, including visual inspections, thermography, partial discharge tests, and other diagnostic methods. Inspections are conducted on a cyclic basis, with frequency determined by:

- Corrosion zones: How quickly the asset is likely to deteriorate.
- Bushfire risk zones: The potential consequences of asset failure.
- Asset criticality: The number of customers relying on the asset.

Inspection cycles are continually optimised, and we monitor network reliability to identify and address emerging trends.

Inspections also gather valuable data to improve our understanding of the asset base. When significant or unexpected failures occur, we conduct detailed investigations to learn more about failure causes. This helps us link asset failures to their observed conditions during inspections, improving our understanding of asset risks and shaping our policies, strategies, and practices.

Various trials are currently underway to adopt new technologies and/or leverage existing technologies. These include trials for the use of drones ‘beyond visual line of sight’ to provide greater flexibility in the inspection program, and trialing drones with thermal cameras to identify hot joints during times of higher load (i.e., in the evenings). We currently use advanced tools and technologies to enhance inspections, including:

- Autonomous drones,
- Fixed-wing aircraft,
- Specialised condition monitoring equipment,
- Light Detection and Ranging (LiDAR) technology.

We are also exploring new data collection methods, such as input from field crews, customers, and emerging technologies, to improve the timeliness and accuracy of our data.

SA Power Networks is moving towards condition-based inspections, focusing on asset condition rather than fixed schedules. This involves expanding our inspection tools to support more field-based activities, including:

- Vegetation management audits,
- Pre-bushfire patrols,
- Substation inspections,
- DC batteries,
- Thermographic inspections.

All staff and contracted inspectors are trained and accredited to Certificate II in asset inspection. Defect rectification is prioritised using SA Power Networks’ Asset Management System, which assigns a risk value to each defect. This value is based on:

- The likelihood of failure within a specific timeframe,
- The potential consequences of failure (e.g., reliability, safety, environmental impact),
- Factors such as asset age, condition, incident history, and industry experience.

Risk scores are calculated by summing all potential adverse consequences of a failure. For example, a single failure might impact reliability, safety, and the environment. This comprehensive risk assessment ensures maintenance and repairs are prioritised effectively to minimise adverse outcomes.

Vegetation Management

The vegetation management program is designed to reduce risks associated with vegetation contacting powerlines, including bushfire, public safety hazards, and electricity supply interruptions. A key focus is maintaining statutory clearances between trees and powerlines as part of bushfire risk mitigation. This includes clearing vegetation from public supply lines and naturally occurring vegetation from private supply lines, in line with the *Electricity Act 1996* Regulations and the *Native Vegetation Act 1991*.

SA Power Networks inspects powerlines in bushfire risk areas on a cycle determined by vegetation growth rates and the extent to which vegetation can be cleared to remain outside the clearance zone until the next scheduled inspection. In non-bushfire risk areas, inspections occur on a three-year cycle. These inspections identify vegetation cutting required to maintain 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.

Asset maintenance

SA Power Network undertakes cyclic asset maintenance (similar to servicing a vehicle) on priority equipment, mostly substation assets.

Asset refurbishment

Where possible and prudent to do so, we repair or refurbish assets to extend their service lives. In addition to ‘patching’ in-service assets (e.g. pole plating), we deploy refurbished transformers, switching cubicles and circuit breakers. Our refurbishment programs have allowed us to extend the life of our assets and reduce the investment required to minimise risk and maintain service levels.

Asset replacement

Asset replacement decisions form a fundamental part of the asset management lifecycle. We take a value-based approach when considering whether to renew or replace an asset. This decision on timing is made by comparing the cost (including risk costs) of retaining the asset in service against the cost of renewal or replacement (or the cost of investing in an alternative solution).

When determining whether an asset should be replaced (or renewed), we assess the *benefit* of replacement, typically expressed as the reduction in risk. On failure, an asset may pose a risk to the public, network workers, the network itself or any other stakeholder in the electricity system. This is summarised by the Risk Cost, which is a measure of the expected monetised value of the risk event. At its highest level, the Risk Cost is made up of three components as follows:

- **Probability of Failure (PoF)**: the probability an asset experiences a functional failure in a given year;
- **Likelihood of Consequences (LoC)**: the probability any given functional asset failure results in a consequence occurring; and
- **Cost of Consequences (CoC)**: the average cost of a consequence that results from the asset failure.

As part of our Asset & Works program, we developed RCM, allowing us to quantify risk costs at an individual asset level. This quantification enables us to forecast risks to service outcomes at an individual asset, asset class or asset portfolio level under various scenarios. We can also forecast the investment required to manage these risks to achieve our required performance outcomes and the customer service that our customers expect.

Our key asset replacement expenditure (repex) programs and their replacement strategies are summarised below.

Overhead conductors

Overhead conductors transmit electricity between substations and from substations to customers. Of the approximately 175,000km of conductors across our network (over a route length of approximately 70,000km), a significant proportion (~80%) are 40–65 years old. Since the 1980’s all new residential developments have been supplied with underground cables rather than overhead conductor.

The life expectancy of conductors varies but is typically 65–95 years. The main factors that influence expected life are distance to coast, material type and diameter.

Our historic, overhead conductor approach of ‘fixing on fail’ with little proactive replacement, will deteriorate the reliability and safety of our distribution network. We have recently been replacing on average less than 150km of overhead conductor per year under our replacement program. This results in a total effective annual volume of less than 0.1% of the population (175,000km) replaced each year. With this replacement rate it would take well over 1,000 years to replace the entire conductor population. This replacement rate may be appropriate, efficient and prudent, when the assets are relatively young but is clearly unsustainable in the long term and is now resulting in increased failures.

We have increased our conductor replacement rate in recent years; however, the year-to-year rate can vary depending on the projects undertaken, such as the project location, the length of conductor to be replaced, and access to the network, including whether the line can be switched off.

Underground cables

The underground cable network, which transmits electricity between substations and from substations to customers, extends for approximately 18,000km.

The significant and sustained 200-400km per annum of cable installed beginning in the 1970's aligns with large scale real estate developments in areas such as West Lakes (1970's) and Golden Grove (1980's and 1990s) extending to outer suburbs and infill developments that require undergrounding of the distribution network since then. A small proportion (~1%) of cables are more than 50 years old. These older cables are predominantly located in the Adelaide CBD where their deteriorating condition has resulted in increasing failures and reliability not meeting jurisdictional service standard targets.

Cables that have failed, resulting in a supply interruption, are typically repaired but not replaced. These repairs often consist of a short section of new cable jointed to the original cable. Unlike most other asset classes (e.g. poles, transformers) cable asset failures do not result in a replacement.

Over the 2020-25 RCP, we replaced on average approximately 6km of underground cable per year under our replacement program, out of a total population of more than 18,000km. This results in a total effective annual volume of 0.03% of the underground cable population. At this rate, it would take 3,000 years to replace the entire underground cable population. We are now seeing an increase in failures in the CBD, which contains our oldest population of cables, and this is impacting on reliability.

The majority of proactive cable replacement is forecast in the Adelaide CBD region to meet the jurisdictional service standard reliability target for the CBD. Our cable replacement plan has been optimised together with augmentation solutions to meet the target at lowest overall cost (replex plus augex), as discussed in section 5.2.3.

Pole replacements

Poles serve as the support structures for overhead conductors, maintaining a safe height above ground and ensuring prescribed safety clearances from other objects. They also support other network equipment such as pole top structures, transformers, reclosers, and voltage regulators. Stobie poles are used almost exclusively across our network and consist of a concrete core with two outer steel beams connected by bolts to ensure strength. This asset class includes a small number of municipal tramway poles (mainly within the LV network) and wooden poles (former Telstra poles with only our assets attached).

When a pole reaches the end of its technical life it may be possible to refurbish ('plate') by welding steel plates at ground level where corrosion typically occurs. This refurbishment is only possible for some poles (i.e. where pole condition makes it suitable to plate).

On average, we have been replacing less than 1,000 poles per year under our replacement program, while deferring 3,000-4,000 replacements through plating. At this replacement rate, it would take approximately 600 years to replace the entire pole population relative to an average life of less than 100 years. Noting this, the recent performance of our pole assets does not suggest an increase in replacement rates is necessary for this asset class in the near term. Our risk modelling shows that a continuation of our current rate of replacement will maintain the current impact on customer reliability and safety risk (including bushfire risk) from our pole assets.

Poles that have failed resulting in supply interruption are replaced immediately. To maintain safe operation of the network, any defected poles identified via routine inspection as no longer able to perform its function as a support structure are also replaced immediately. For the remaining defects, we assess the most cost-efficient treatment to remove as much risk from the network as possible. Where efficient and feasible, poles are plated to reinforce the base instead of being completely replaced. Pole plating significantly extends the life of the asset at a much lower cost than complete replacement.

Pole top structures

Pole top structures enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment, and connect the overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps, and other components. As this asset class comprises a very large number of small assets, we have limited data on this asset population.

Defective pole top structures are managed through replacement or refurbishment based on an assessment of benefits and costs, with failed assets replaced as required.

Circuit breakers

Our historic approach to circuit breakers has been to proactively manage this equipment based on condition and risk and, where efficient, to extend their life via refurbishment. We consider that maintaining this approach, together with our historic replex spend level, is likely sufficient. By contrast, a ‘run-to-fail’ approach would be expected to degrade service.

Hindley Street substation 66kV switchgear

This key CBD substation is deteriorating. A do-nothing option (no capex investment) presents a reliability risk, with the deteriorated condition of circuit breakers posing risk of catastrophic failure and resulting safety risk. SA Power Networks is planning to replace the Hindley Street substation 66kV switchgear commencing early 2028.

Northfield 66kV GIS switchboard replacement

The Northfield 275/66/11 **kilovolt (kV)** Connection Point Substation is a key link in the 66kV interconnected network that supplies approximately 115,000 customers in Adelaide’s eastern suburbs. It was installed in the late 1980s and components of its infrastructure have reached the end of their service lives and are in poor condition. In particular, the **gas insulated switchgear (GIS)** that forms part of the substation is in poor mechanical condition and subject to accelerated ageing. These condition issues are principally a result of significant external corrosion caused by 35 years of continuous service in an outdoor environment.

Construction of a new Northfield 66kV **air insulated switchgear (AIS)** substation is well advanced, being the preferred option per the RIT-D. This option involved constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation.

Due to the complexity of the project and the required interfacing with ElectraNet, the works are being undertaken in multiple stages. Stage 1 is scheduled for completion in September 2026, Stage 2 in June 2027, and Stage 3 in late 2030, after which the 66 kV outdoor GIS will be fully decommissioned.

Mobile substations project

A base case of only doing minor refurbishment and regular maintenance of our mobile substations poses risks that defects in these substations will increase the risk to reliability. SA Power Networks is proposing to replace two 10MVA mobile substations, one 11kV mobile switchboard in the 2025-30 period.

Other asset replacement programs

These comprise a broad range of asset classes each of which contribute less than 10 percent to total forecast repex. They include high volume assets, with the forecast based on: volumetric risk-based modelling for work that is condition-based; historic spend for reactive work; and historic spend for high volume assets for which there is insufficient data for modelling.

Network augmentation

SA Power Networks must comply with the requirements relating to reliability and system security contained in Schedule 5.1 of the NER and with the service obligations imposed by the EDC. We have developed our 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 (i.e. a network constraint) a suitable solution is developed which may involve a major network augmentation, a deferral solution or a suitable contingency plan taking all risks and their associated consequences into consideration.

For the 2025-30 RCP we are trialling a hybrid approach to forecasting augmentation. The hybrid approach combines *probabilistic* and *deterministic* methodologies to produce targeted investment in two distinct categories:

- 1) projects required to avoid unserved energy risks forecast at a 10 POE level under normal operating conditions; and
- 2) projects required to address contingency (N-1) scenarios that are NPV-positive to deliver in 2025–30, identified via the application of probabilistic (economic) analysis.

This presents a balanced approach to expenditure over the 2025–30 RCP that recognises and assists with the general affordability concerns expressed by our customers; and provides an opportunity for the maturation of non-network solutions and other developing technologies (e.g. flexible load connections) to address the demand forecast. Our planning methodology is discussed in detail within our DAPR⁷.

Maintaining reliability

The reliability of customer's supply (due to unplanned activities) is driven by various factors, including:

- unplanned network outages, which can arise from a range of causes including asset failure due to their age/condition, vegetation and animals contacting the network, lightning, and third parties contacting or damaging the network; where storm activity can be a significant driver of many of these causes;
- network protection and switching arrangements, particularly the location of switches on the network and the method of switching (e.g. via manual actions requiring a field trip, remote switching from the control room, or automatic switching or reclosing), affects how many customers are interrupted due to a network outage, how fast the network can be rearranged to restore some or all interrupted customers, or whether the switch can automatically restore the network if the outage was only temporary;
- fault response arrangements and practices, affects how network outages are identified and responded to, including addressing or repairing specific causes of outages, and restoring supply to interrupted customers; and
- where a customer is located on the network, how far a customer is located from a bulk supply point and the length of line that supplies a customer from the bulk supply point and the terrain the lines traverse.

⁷ The DAPR can be found on SA Power Networks' website [here](#)

Furthermore, reliability patterns change over time, driven by:

- internal factors, such as the aging of the network assets; and
- external factors, such as the changing environment of the network and changing customer patterns.

These changes result in new issues emerging that cause outages, or changes in the pattern of outages, or changes in the customers who receive poor performance (compared to other similar cohorts).

We have standard programs to mitigate these ongoing changes (e.g. our network inspection, maintenance and repx programs address the ageing of the network assets). Nonetheless, historically, we have always required ongoing reliability programs to maintain reliability and improve it where appropriate.

The reliability programs typically involve works such as:

- addressing outage causes (excluding those addressed through the other programs) by upgrading the network to make it less prone to certain outage causes (e.g. replacing bare wire overhead spans with covered conductor or undergrounding);
- reduce the number of customers interrupted due to a network outage by adding mid-line switches to feeders; and
- reducing the restoration time of interruptions by enhancing operational practices, installing remote controlled switches and automation, and fault locating devices.

The Reliability Management Programs are required to:

- maintain underlying reliability of the supply to SA Power Networks' customers at historical levels (consistent with the **Service Targeted Performance Incentive Scheme (STPIS)** setting for the next regulatory period); and
- improve the reliability of supply to the worst served areas of the SA Power Networks network where the STPIS does not provide sufficient incentive to undertake the investment.

The improvement programs include some elements where it is expected that our network could exceed jurisdictional reliability service standards applicable in the next regulatory period. However, the reliability improvement component only includes programs supported by our customers that can be demonstrated to provide a net-benefit to customers.⁸

These improvement programs are focused on improving the supply reliability for the following worst served customers:

- **CBD improvement program** - customers in the CBD, where the reliability of the network has been declining significantly since 2015 and is now expected to exceed the jurisdictional service standards;
- **supply restoration time improvement program** - customers supplied from rural feeders whose average time to restore supply following an interruption has been declining and is expected to exceed the jurisdictional service standards associated with maximum restoration times;
- **low reliability feeder improvement program** - customers supplied from a feeder whose reliability performance over the last five years has been consistently much poorer than the regional average resulting in the feeder being defined as a 'low reliability feeders' on multiple occasions under the jurisdictional service standard arrangements⁹; and

⁸ Though the ESCOSA review, we will later determine the extent to which some of these programmes may be required on regulatory compliance grounds.

⁹ The definition of a 'low reliability feeder' under the jurisdictional service standard arrangements is defined in the South Australian Electricity Distribution Code and is summarised further in this forecasting approach document.

- regional improvement program - customers in those regions that have the worst reliability compared to the overall regional average or regions where reliability has seen an appreciable decline recently.

Maintaining reliability to achieve service targets, must take priority over expenditure on reliability improvement programs for worst served customers.

Service target performance incentive scheme

SA Power Networks is required to operate within a STPIS, in accordance with the NER. The intent of the STIPS is to provide SA Power Networks with a financial incentive to maintain and improve reliability and customer service (telephone response – maximum of 0.5%) performance. The revenue at risk under the STIPS is $\pm 5\%$ of SA Power Networks' annual revenue, or around \$52 million per annum on average (i.e. \$260 million over the five-year regulatory period).

The STPIS is based on SA Power Networks' annual unplanned SAIDI and SAIFI performance against targets set in four feeder categories CBD, Urban, Rural Short and Rural Long, measured over each financial year.

The STPIS targets exclude:

- Transmission/generation/emergency disconnections;
- Momentary interruptions (duration is ≤ 3 minutes);
- Planned interruptions; and
- Interruptions commencing on MEDs, where the daily SAIDI exceeds 4.718 minutes (this is the threshold for the regulatory year 2024–25).

Any departure from these performance targets will result in an incentive or penalty to SA Power Networks via a distribution revenue adjustment. A distribution revenue adjustment (increment or decrement) can be delayed in any one regulatory year to smooth customer price variations (referred to as the 's-bank' mechanism).

SA Power Networks has not been funded to a level sufficient to maintain reliability performance through the 2025–30 period and undertake all of our proposed reliability improvement programs. Reliability improvement programs such as improving worst performing feeders, will need to be balanced with business-as-usual programs in order to maintain the network to achieve the maximum customer benefit (assuming average weather performance over the regulatory period).

Decisions from SA Power Networks' STPIS Steering Committee¹⁰ inform the **Reliability Management Plan (RMP)**.

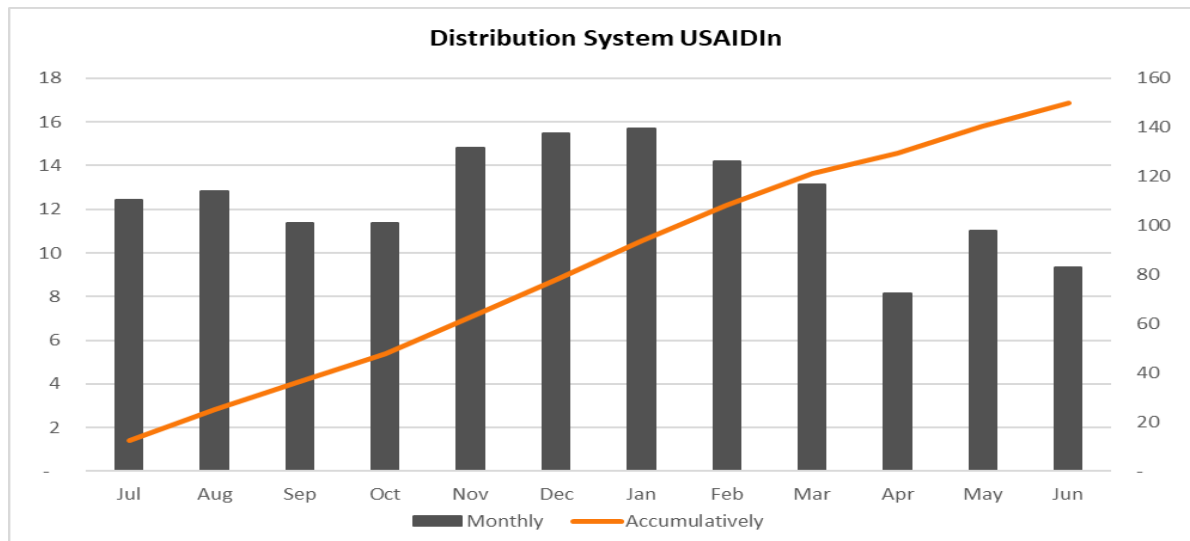
How we monitor and evaluate our performance

To effectively monitor our performance against the service standards, we calculate 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, a typical 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 (i.e. just under 16 minutes) and the lowest in April (i.e. just over 8 minutes).

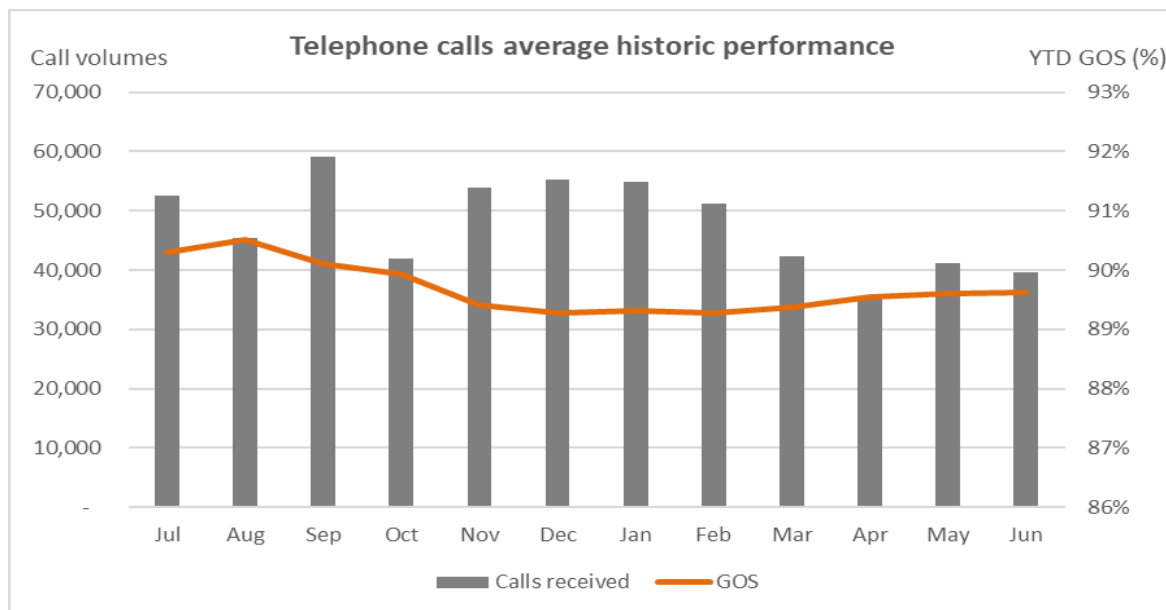
¹⁰ The SPS Steering Committee meets monthly and comprises senior Asset Management and Operations personnel.

Figure 1: Typical distribution system monthly USAIDIn



The following graph shows the typical monthly variability in telephone call volumes and the associated impact on the year-to-date **Grade of Services¹¹ (GOS)**.

Figure 2: Telephone call response



These monthly profiles enable us to monitor and determine if the service standard targets will be achieved by 30 June. They enable the identification of any negative variations in performance during the year that require investigation to determine the cause(s) and whether they are systemic or one-off causes. Generally, most variations from the profiles are due to one-off faults or 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 (ELT)¹²**. Any negative deviations from the service standards profiles are highlighted for further investigation and rectification where

¹¹ The percentage of telephone calls answered within 30 seconds from five published telephone lines.

¹² The Executive Leadership Team includes all Departmental Chief Executive Officers.

the cause is systemic. 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 outweigh the costs.

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. We note this may require redesign of infrastructure and may take some time 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.

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 **Service Performance Scheme¹³ (SPS)** Steering Committee (see below), to monitor the performance of the four feeder categories, identify emerging systemic issues and monitor improvement projects and programmes to remedy those systemic issues.

SPS Steering Committee

As mentioned above, SA Power Networks is required to operate within a STPIS in accordance with the NER. A SPS Steering Committee has been formed to maximise opportunities and reduce risk arising with respect to the Scheme.

The Committee's purpose is to:

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

The Committee meets monthly and comprises senior Asset Management and Operations personnel.

¹³ Historically SA Power Networks operated under ESCOSAs Service Performance Scheme. SA Power networks now operates under the AERs STPIS, however the SPS reference has remained within the business.

Asset Performance Review Committee

The purpose of the **Asset Performance Review Committee (APRC)** is to manage and monitor asset performance trends, develop and endorse mitigation strategies and to report the findings to the Asset Management steering committee. The APRC is responsible for reviewing:

- Performance against Asset Management Objectives (AMOs);
- Asset Performance issues as referred by the SPS Steering Committee;
- Asset Performance issues as referred by the AM&O Risk Working Group;
- Equipment failure investigations; and
- Asset inspection results.

The APRC assists the SPS Steering Committee in the development of a rapid response to asset performance issues.

3.3.2 Network restoration measures

Service standard definition

EDC Clause 2.2.2 requires SA Power Networks to 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 Table 5 for each year ending 30 June.

Table 5: SA Power Networks' network restoration targets

Target	Single interruption duration	CBD	Urban	RS	RL
	Interruption equal to or greater than 1 hour	11			
	Interruption longer than 2 hours	4	27		
Percentage of total customers in each feeder category per annum	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

SA Power Networks is only required to report on how it has applied its *best endeavours* if its performance is worse than the reporting thresholds set out in Table 6.

Table 6: Interruption reporting threshold

Reporting threshold	Interruption duration	CBD	Urban	RS	RL
	Interruption equal to or greater than 1 hour	13.5			
	Interruption longer than 2 hours	6.5	29.5		
Percentage of total customers in each feeder category per annum	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

Clause 2.2.3 requires SA Power Networks to use its best endeavours to minimise interruptions to supply. Whilst there are no specific measures in addition to the requirements listed above, we must use our best endeavours to:

- Minimise planned interruptions or limitations to supply and unplanned interruptions or limitations caused by:
 - carrying out maintenance or repair work to the distribution network;
 - connecting a new supply address to the distribution network; or
 - carrying out augmentations or extensions to the distribution network, and
- restore supply as soon as reasonably practicable.

Our strategies

To manage network access, outages and/or major incidents we make use of a number of strategies. The primary policies and strategies are summarised below.

Network Operations Centre

The fault management process and monitoring of SA Power Networks' electricity network are managed by Network Controllers operating from the **Network Operations Centre (NOC)** at the Keswick head office. This function is in real-time and is conducted on a 24/7 basis.

Specifically, the NOC:

- Processes all information in relation to supply issues on the high voltage network;
- Provides technical direction on fault diagnosis to field response crews;
- Prioritises fault conditions, directs and coordinates field response crews in fault finding and initiating corrective action;
- Provides safe access and switching coordination for planned and unplanned outages, including bushfire switching programs;
- Manages load by ensuring plant and equipment are within ratings;
- Records, processes and manages emergency services, sensitive loads, priority customer and general major customer supply enquiries; and
- Provides proactive responses on supply matters to major customers and SA Power Networks' stakeholders.

In 2012, a fully redundant backup NOC was established at Angle Park. This was a significant investment, with the site providing:

- A modern control facility for Network Controllers, equipped with eight workstations;
- Electricity supply redundancy for the site by way of uninterruptible power supply and generator back-up;
- A telecommunications operations centre disaster recovery site; and
- Redundancy for critical operational systems across primary and secondary data centres including **Supervisory Control and Data Acquisition (SCADA)** systems.

Advanced Distribution Management System

The **Advanced Distribution Management System (ADMS)** is a central, integrated and dynamic system used for managing and monitoring our 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 the **Australian Energy Market Operator (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 digital representation of the electrical transmission network, sub-transmission system and distribution network that illustrates the network connectivity,
- integration with other enterprise systems: enabling of integration with the SAP works management system, Outage 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 to support all planned and unplanned HV switching. Performing electronic HV switching on a connected network model in ADMS leads to increased visibility of the real-time state of the network, leading to more efficient supply restoration times and a decrease in HV switching incidents.

Maximum restoration supply 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 dispatchers are responsible for escalating any unplanned interruption where the number of customers and/or the forecast restoration time exceed a specified threshold.

Where an unplanned interruption is escalated, a leader is responsible for resolving any resourcing (e.g. labour, materials, vehicles) issues (within authority levels), in an attempt to achieve or better these thresholds.

If 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, the department ‘Head of’ and the **Incident Response Manager (IRM)**.

Where it is apparent that the thresholds are not achievable, the Operations Manager, or their delegate, are responsible for advising customer and media relations teams. In conjunction with these groups, the customer and media management strategies will be implemented.

Management of emergency response (including major event days)

SA Power Networks’ **Emergency Response Manual** sets out our procedures for emergencies associated with our distribution network. It specifies the roles and responsibilities for all groups that respond to network emergencies, including outages to supply, network security, and environmental incidents.

SA Power Networks has four response levels, from the lowest being emergency response level zero (ERL0) for normal daily operation, to the greatest being ERL3 (see

Table 7 below). There are four phases associated with emergency response being: preparation, pre-Event, during the Event and post-Event (i.e. review).

The **Emergency Management Team (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.

Table 7: Emergency response levels

Network emergency level	Event characteristics	Summary response
ERL0	<ul style="list-style-type: none"> Normal daily operation 	<ul style="list-style-type: none"> Normal response
ERL1	<ul style="list-style-type: none"> Localised strong to gale force winds ≤ two days high (maxima, minima) temperatures Localised Severe lightning 	<ul style="list-style-type: none"> Resources increased in impacted areas Resources placed on standby
ERL2	<ul style="list-style-type: none"> Widespread gale or strong winds > two days high (maxima, minima) temperatures Widespread Severe lightning 	<ul style="list-style-type: none"> Incident Response Manager (IRM) convenes Emergency Management Team (EMT) EMT prepares operational response plan Continuous shift rostering
ERL3	<ul style="list-style-type: none"> Widespread, protracted, multi-day Network restoration event 	<ul style="list-style-type: none"> Continuous shift for all operational staff including EMT, Call Centre and field crews IRM convenes EMT CMT¹⁴ is convened

Restoration prioritisation

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. It should be noted, however, that the overriding priority across all jobs is the safety of people, both powerline workers and the wider community. Accordingly, 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 based on the priorities listed below. Re-prioritisation may occur in response to new outages, or as new information becomes available.

Table 8: Restoration of supply prioritisation

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

An interruption affecting large numbers of customers is typically given priority over an interruption affecting a small number of customers. However, consideration is also given to restoring an interruption affecting small numbers of customers where those customers have been without supply for a longer period.

¹⁴ CMT ≡ corporate Crisis Management Team

Emergency management

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 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 are recorded and all significant emergency response efforts are reviewed to identify opportunities for improvement.

Social media

SA Power Networks employs Facebook, X, 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 messages 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.

How we monitor and evaluate our performance

Our reliability performance monitoring is set out in Reliability measures, above.

3.4 Guaranteed service level scheme

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, and
- minimise the frequency and the total duration of unplanned supply interruptions¹⁵.

3.4.1 Connection of a new supply address

Service standard definition

EDC 2.3.1(a) specifies that SA Power Networks is required to connect a customer's electricity supply to new supply address within the EDC specified timeframes. We must use best endeavours to provide infrastructure to enable a connection for a customer's new supply address either:

- on a date agreed with the customer, or
- where no date has been agreed with the customer, within 6 business days after the customer has met all the necessary pre-conditions for connection and supply is readily available adjacent your premises.

SA Power Networks must pay the customer \$65 (including GST) for each day it is late in connecting the customer, up to a maximum of \$325 (including GST).

¹⁵ For the purpose of EDC clause 2.3, the term interruption is defined as a planned or unplanned interruption of, or restriction to, supply of at least three minutes in duration, other than an interruption or restriction due to an emergency, or an interruption on a CBD feeder, urban feeder, rural short feeder or rural long feeder (but not on a SAPS feeder) due to a generation failure or a transmission failure.

This GSL payment only applies in situations where any required extension and/or augmentation of the distribution network to affect the connection has been completed.

Our strategies

SA Power Networks has established systems and processes to agree upon a connection date (the "agreed date") with customers receiving a basic connection service, through their electrical contractor. Self-service facilities are available to electrical contractors to enable them to book and manage connection service requests. In addition, a dedicated contact centre is available to assist customers and electrical contractors who wish to discuss or amend connection service requests.

Once a booking is confirmed, the connection date is set and recorded in SA Power Networks' systems. The actual date on which the premises is connected is also recorded. Where the actual connection date occurs after the agreed date, the customer is entitled to receive a GSL payment, calculated according to the number of days between the agreed date and the actual connection date, up to a maximum of \$325.

Performance against this obligation is monitored and evaluated through regular review of connection service records maintained in SA Power Networks' systems. This includes tracking the agreed connection date, the actual connection date and any variance between the two.

Reporting is used to measure the number and proportion of connections completed on or before the agreed date, to identify instances where the agreed date was exceeded, and to ensure that any associated GSL payments are calculated and issued accordingly.

3.4.2 Reliability GSL payments

Service standard definition

EDC Clause 2.3.1(c) specifies that SA Power Networks must use its best endeavours to minimise the frequency and duration of supply interruptions to a customer's supply address. If the total number of interruptions and/or the total duration of all interruptions across a regulatory year exceeds the thresholds in the following Table 9 and Table 10 below, we must make payments (GSL reliability payments) to customers experiencing interruptions as set out in those tables.

Table 9: Thresholds and payment amount - Frequency of interruptions

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

Table 10: 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 (i.e. typically in October/November each year). Payments will be made in respect of the supply address, not the customer. The resident of the supply address will receive a SMS or letter advising them of the reliability GSL credit that has been applied to their electricity account.

For the purposes of the EDC clause 2.3, the term interruption is defined as a planned or unplanned interruption of, or restriction to, supply of at least three minutes in duration, other than an interruption or restriction due to an emergency, or an interruption on a CBD feeder, urban feeder, rural short feeder or rural long feeder (but not on a SAPS feeder) due to a generation failure or a transmission failure, the above scheme also excludes:

- (i) interruptions caused by disconnection required by law;
- (ii) Interruptions caused by single customer faults caused by that customer;
- (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.

Our strategies

SA Power Networks seeks to minimise the frequency and duration of supply interruptions for all customers across our distribution network. Noting this, we acknowledge we are not always able to maintain reliability of supply or restore supply within the timeframes. For example, reliability GSL payment include interruptions on MEDs, which can result in significant variation in reliability GSL payments. For example, a total of \$1.6M was paid to customers for reliability GSL payments in 2020–21 and a total of \$14.7m in 2022–23. The main reason for this significant variation results from the number and severity of the MEDs in 2020-21 compared to 2022–23. There were three MEDs contributing 30 minutes to USAIDI in 2020–21 and six MEDs contributing 262 minutes to USAIDI in 2022–23.

SA Power Networks has systems and process in place to record the number of interruptions and the duration of each interruption that are experienced by customers. This same reliability data is used to report annually to ESCoSA and the AER on the reliability performance by feeder category. This same data is used to report on the AER’s STPIS. The reliability data is audited annually by an external auditor, who verifies the accuracy of the reliability data.

SA Power Networks has developed reports which interrogate this reliability data to determine which premises (supply address) are eligible for a reliability GSL payment. These reports are run after internal quality checks of the reliability data. Payments are then credited to the current customers electricity accounts. SA Power Networks notifies customers using electronic communication that they should have received their reliability GSL payment for the year ending 30 June in October/November each year.

3.4.3 Interruptions outside control of SA Power Networks

If an interruption arises from one or more events or circumstances that are not caused by and are outside the control of SA Power Networks and we are prevented from restoring supply for reasons outside of our control, or reconnection may result in serious harm, the period for which we cannot reinstate supply will not be counted within the GSL timeframes.

SA Power Networks must use best endeavours to provide prompt notice to affected customers including details of the event, an estimate of likely duration, the extent to which obligations are affected and the steps taken to remove, overcome or minimise those effects. However, we do not have any reporting obligations relating to these supply interruptions.

For further information refer to EDC Clause 2.3.2.

Our strategies

For SA Power Networks to provide prompt outage notification to customers, using best endeavours, during supply outages beyond our control, we employ the use of social media and text messaging to promptly inform affected customers of our supply restoration progress, see Social media above.

To manage major outages or incidents efficiently and safely we make use of a number of strategies. These are set out in Network restoration measures, above.

3.5 Reconnection after disconnection

In summary, EDC Clause 2.4.1 specifies that 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 received 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 2.4.1 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 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.

Our strategies

SA Power Networks has established systems, processes and procedures to monitor all reconnection service orders and the associated completion timeframes to support compliance with this obligation. The majority of these orders are completed by our external contractor and we have **key performance indicators (KPIs)** in place to monitor, manage and address their performance against these obligations.

We also hold fortnightly meetings between operational teams, as well as monthly meetings with senior leaders, to review all relevant KPIs and monitor performance against these obligations. Where a reconnection is not completed within the specified timeframe, an investigation is initiated and corrective action is taken to prevent further non-compliance.

How we monitor and evaluate our performance

SA Power Networks monitors performance against reconnection timeframe obligations through system-based tracking of all reconnection service orders, supported by KPI reporting and exception management. As the majority of these orders are completed by our external contractor, contractor performance is monitored against agreed KPIs and any delays or non-compliances are reviewed and addressed. Performance is regularly evaluated through fortnightly operational meetings and monthly senior leadership meetings, where KPI results, trends and any overdue orders are reviewed, and corrective actions are identified to support ongoing compliance.

4. Environmental and external factors

This section explains the external factors that influence the reliability of the distribution network and the overarching mitigation practices to manage these impacts.

4.1 Interruption to supply causes

The causes listed in Table 11 are used to classify unplanned interruptions to supply. We use this information to monitor our network performance and to identify trends in performance. It is important that detailed information is recorded against each unplanned outage to determine the cause so that trends can be determined and where required actions take to address a specific cause trend.

Table 11: Unplanned outage cause categorisation

Guideline No.1 cause	Simple Cause	Internal cause	Sub-cause
Equipment Failure	Equipment failure	Cable Fault	Cable Insulation Breakdown
Equipment Failure	Equipment failure	TF Failed	Internal Fault
Equipment Failure	Equipment failure	TF Failed	TF Failed (Age)
Equipment Failure	Equipment failure	Regulator Faulty	Internal Fault
Equipment Failure	Equipment failure	Conductor Failed	High Resistance Joint (Hot Joint)
Equipment Failure	Equipment failure	Conductor Failed	Corrosion
Equipment Failure	Equipment failure	Conductor Failed	Vibration
Equipment Failure	Equipment failure	Tap Failed	High Resistance Joint (Hot Joint)
Equipment Failure	Equipment failure	Tap Failed	Corrosion
Equipment Failure	Equipment failure	Tap Failed	Vibration
Equipment Failure	Equipment failure	Line Plant Failed	Wear or Abrasion
Equipment Failure	Equipment failure	Sectionaliser Faulty/ Damaged /Did not operate	Failed to Operate
Equipment Failure	Equipment failure	Recloser Faulty / Damaged / Did Not operate	Failed to Operate
Equipment Failure	Equipment failure	Switching cubicle failed	Internal Fault
Equipment Failure	Equipment failure	Pole Failure	Corrosion
Equipment Failure	Equipment failure	Substation plant failed	Internal Fault
Equipment Failure	Equipment failure	Wood Rot	Wood Rot
Equipment Failure	Equipment failure	Mechanical	Age
Equipment Failure	Equipment failure	Mechanical	Mechanical Overload
Equipment Failure	Equipment failure	Mechanical	Gasket Failure
Equipment Failure	Equipment failure	Design / Standards / Installation	UV Degradation
Operational	Other	Switching Error	Switching Error
Operational	Other	Overload	Electrical Overload
Operational	Other	Forced Interruption (Emergency or 15 Minute Rule)	Check / Inspect Equipment
Other	Other	Protection Issue	Protection Settings
Other	Other	Conductor Clearance Issue	Clearances Insufficient
Other	Other	Design / Standards / Installation	Faulty Workmanship
Other	Other	Design / Standards / Installation	Non Standard - Connections
Other	Other	Design / Standards / Installation	Not to current - Standards
Third Party	Other	Work Procedure Error	Human Error (Switching Error)
Third Party	Other	Foreign Object	Object on Mains
Third Party	Other	Animal	Rats, Snakes, Cats - Misc Animals & Insects
Third Party	Other	Animal	Bees
Third Party	Other	Animal	Birds

Guideline No.1 cause	Simple Cause	Internal cause	Sub-cause
Third Party	Other	Animal	Possums
Third Party	Other	Animal	White Ants
Third Party	Other	Animal	Bats & Flying Foxes
Third Party	Other	Bushfire Damage	Vandalism
Third Party	Other	Bushfire Damage	Bushfire
Third Party	Other	Tree Felling	Tree Felling
Third Party	Other	Animal Nesting	Animal nesting
Third Party	Other	Third Party	U/G Cable Dug Up
Third Party	Other	Third Party	Vandalism
Third Party	Other	Third Party	Vehicle/Machinery/Crane etc Hit ETSA Eqp
Unknown	Weather	No Cause Found	Feeder/Line Patrolled - No Cause Found
Unknown	Weather	No Cause Found	Nothing found/suspected
Unknown	Weather	No Cause Found	Suspect Animal / Bird
Unknown	Weather	No Cause Found	Suspect Vegetation
Unknown	Weather	No Cause Found	Suspect Weather
Weather	Weather	Vegetation	VEG detached - INSIDE clearance zone
Weather	Weather	Vegetation	VEG detached - OUTSIDE clearance zone
Weather	Weather	Vegetation	VEG attached - INSIDE clearance zone
Weather	Weather	Vegetation	VEG attached - OUTSIDE clearance zone
Weather	Weather	TF Failed	Lightning
Weather	Weather	Regulator Faulty	Lightning
Weather	Weather	Conductor Failed	Lightning
Weather	Weather	Tap Failed	Lightning
Weather	Weather	Lightning	Lightning
Weather	Weather	Foreign Object	Wind Blown Debris
Weather	Weather	Insulator Failed	Lightning
Weather	Weather	Insulator Failed	Lightning from previous storm
Weather	Weather	Insulator Failed	Pollution
Weather	Weather	Bushfire Damage	Lightning
Weather	Weather	Pole Failure	Erosion or Subsidence
Weather	Weather	Flooding	Flooding

The major categories of unplanned interruptions are grouped as follows:

- Equipment failure;
- Animal;
- Third Party
- Weather (including lightning);
- Vegetation;
- 'Other'; and
- Unknown.

4.2 Monitoring

SA Power Networks monitors the reliability of feeders on a daily basis to detect systemic issues on specific feeders that require action to improve the feeder's reliability performance.

4.3 Reducing the number of customers interrupted

Where it is not feasible to mitigate the cause of an outage, it may be more effective to reduce the number of customers interrupted by the event.

4.3.1 Section fusing

SA Power Networks is undertaking a program during **2025 and 2026** to install fuses on additional high-fault sections of line in metropolitan areas and larger rural centers. The purpose of this program is to reduce the number of customers interrupted during network faults. This initiative is supported by a review of fuses installed in 2010, which demonstrated reliability benefits.

4.3.2 Feeder automation (self-healing networks)

SA Power Networks has been using self-healing networks for almost a decade and will continue to expand the deployment of **distribution feeder automation (DFA)** across the network.

A self-healing network detects a network fault and automatically undertakes switching operations to isolate the affected feeder section, being the section between remote-controlled switches in which the fault is located. It then restores supply to unaffected sections of the network from alternative sources, where available. This reduces the number of customers affected by the fault and limits the extent of the unplanned interruption. Network reconfiguration is typically completed in less than one minute.

The effectiveness of DFA depends on the availability of alternative sources of supply to restore power to customers. It also requires those sources to have sufficient capacity to accommodate the additional customer load.

5. Current issues impacting network reliability

5.1 Network reliability trends and performance

This section summarises recent network reliability trends in outage frequency, outage duration, and the key drivers of USAIDIn and USAIFIn performance impacts. While USAIFIn has improved against historical levels, USAIDI has increased, driven mainly by weather-related and low-voltage outages across the **Greater Adelaide Metropolitan Area (GAMA)** and regional areas.

Figure 3 below shows that, since 2020, USAIFI has remained relatively stable, while USAIDIn has shown an increasing trend. Despite the increase in outage duration, overall USAIFIn performance has improved significantly compared with historical levels. This improvement has largely been driven by a substantial reduction in the frequency of outages on the 11kV distribution network within the GAMA, resulting from the rollout of feeder automation across the region. The impact on state-wide SAIFI has been particularly pronounced because GAMA contains a significantly larger proportion of the state's customers than the remainder of the network.

Figure 3: Historical network USAIDIn and USAIFIn performance

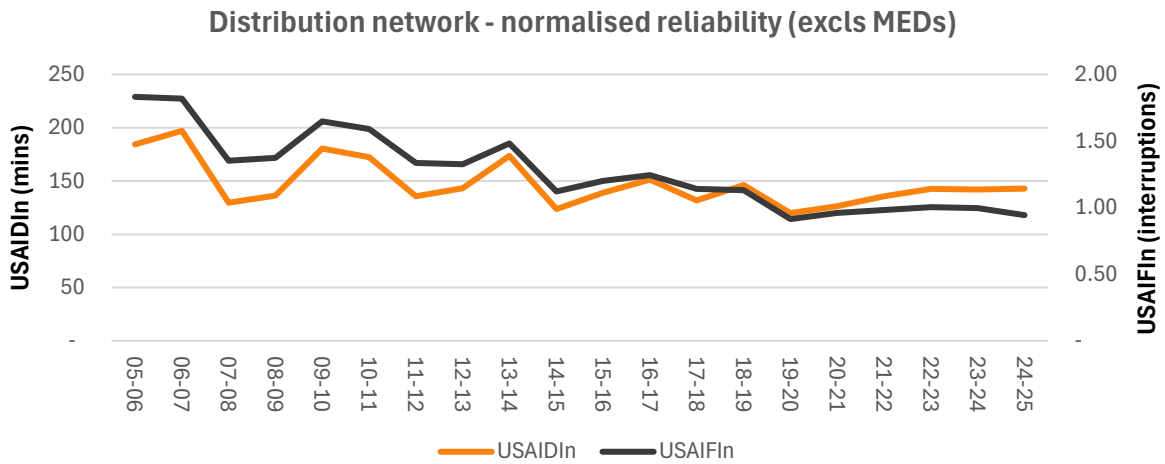
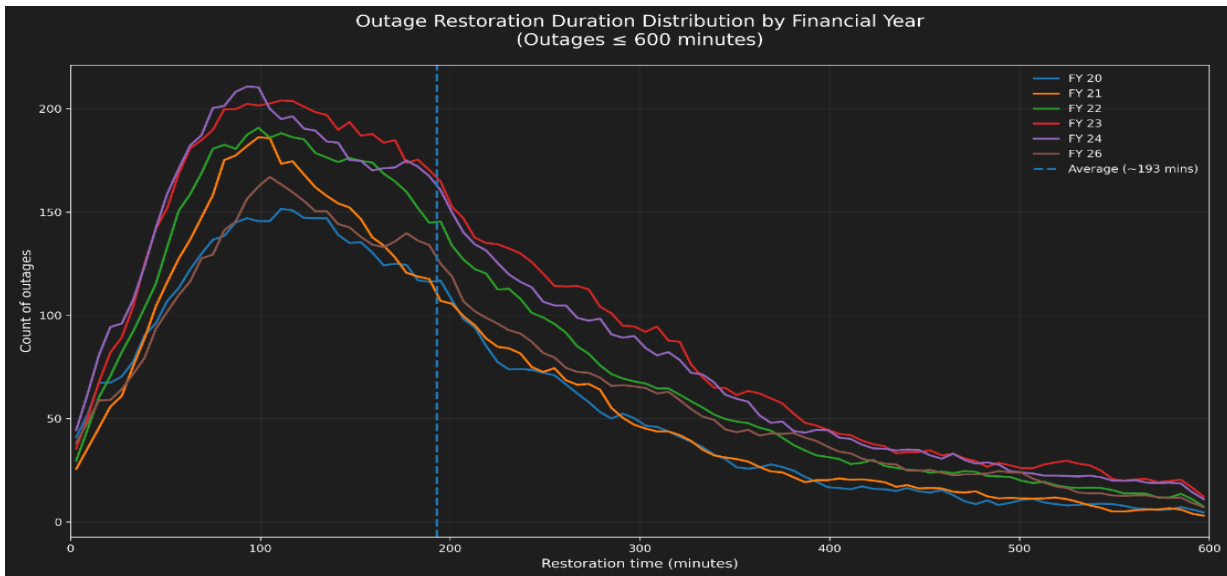


Figure 4 shows that the overall supply restoration times have not increased over the 2020-25 RCP.

Figure 4: Outage restoration duration



The increasing trend in state-wide USAIDIn is largely driven by a significant rise in USAIFI in regional areas, primarily due to an increase in weather-related outages, with the main escalating causes being insulator pollution (weather-related) and coastal crossarm corrosion (equipment failure).

The GAMA USAIDI has also increased due to an escalation in vegetation-related outages originating from outside the prescribed clearance zone and low-voltage outages caused by asset failures, electrical overload, and third-party contact.

Figure 5 shows the USAIDIn impact by cause and Figure 6 demonstrates the increasing trend in LV impacts on USAIDIn.

Figure 5: USAIDI by cause

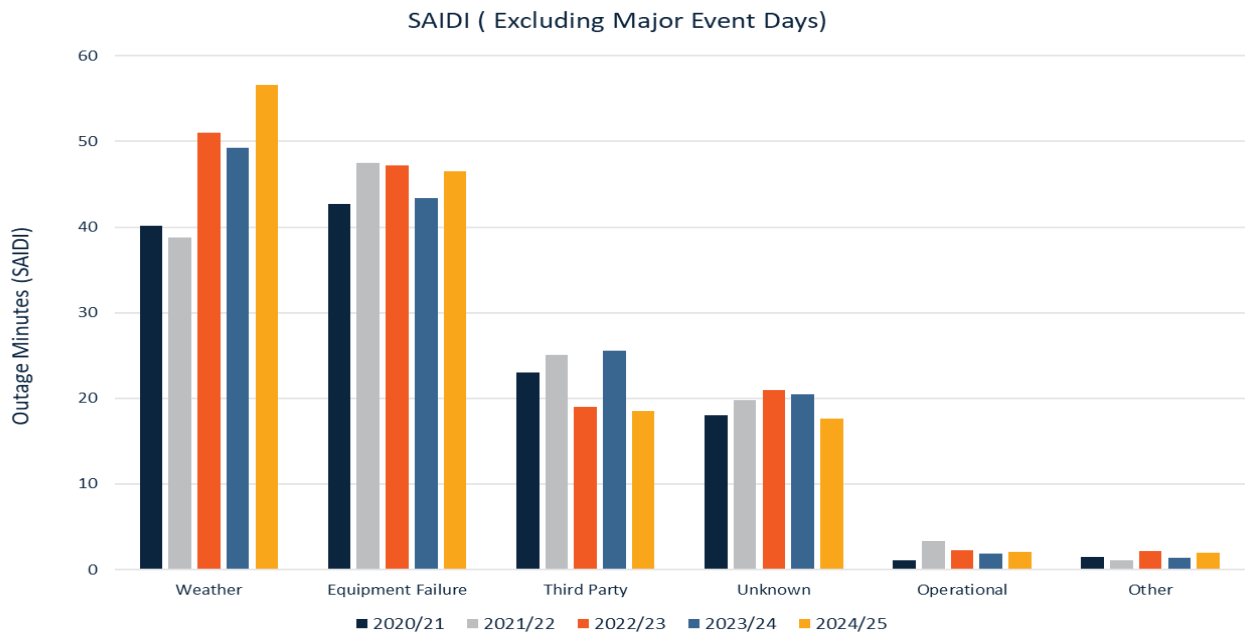


Figure 6: High Voltage (HV) and Low Voltage (LV) USAIDI

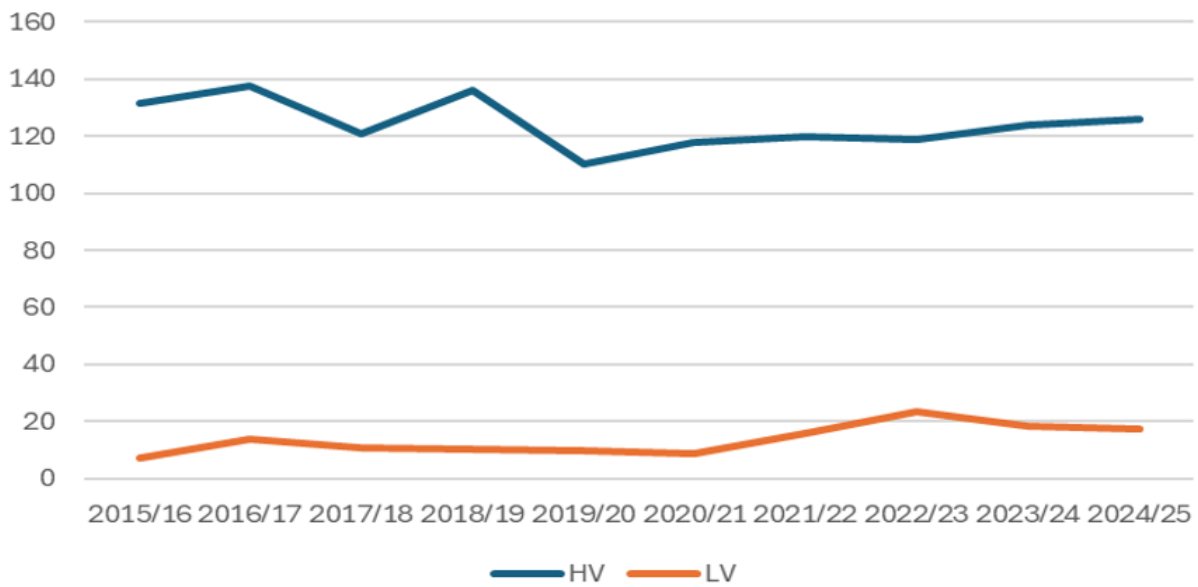
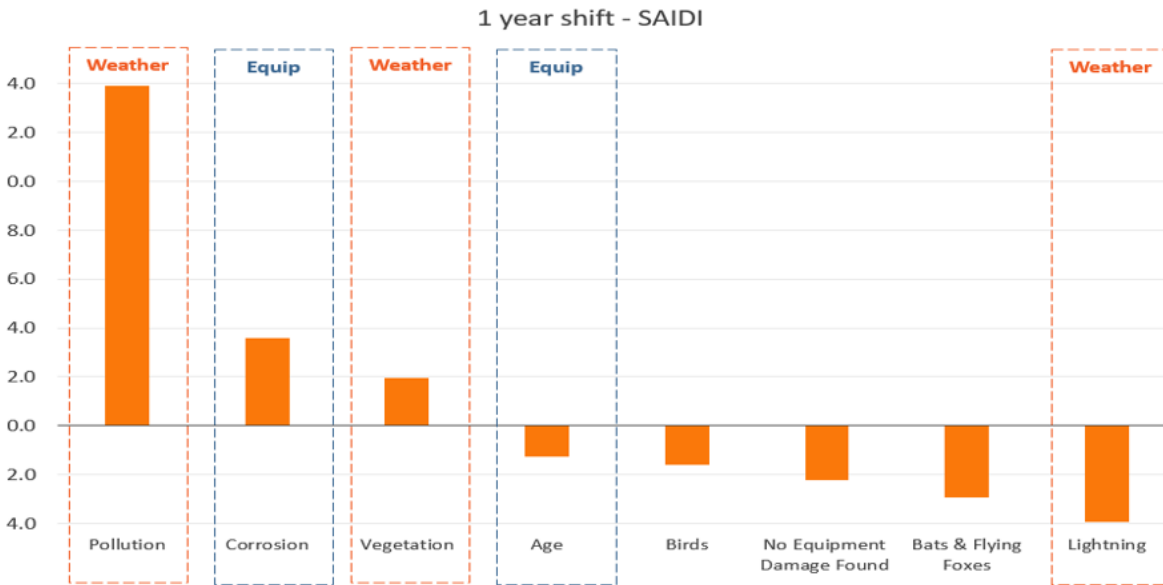


Figure 7 shows the movement in reliability impacts in 2025 compared to our average historic performance.

Figure 7: USAIDIn largest shifts compared to historic performance



The LV USAIDIn has increased by 8.4 minutes per annum over the past three years. LV outages now account for 14% of total USAIDIn, compared with 9% over the previous three-year period.

In summary, the recent increase in USAIDIn has been driven by:

- Insulator pollution (weather)
- Coastal crossarm corrosion (equipment failure)
- Vegetation (weather)
- Low-voltage faults (equipment failure)

This has been partially offset by reductions in USAIDIn associated with:

- Lightning (weather)
- Bats (third party)
- No equipment damage found (unknown)
- Birds (third party)
- Age (equipment failure)

5.2 Network reliability impact mitigation

This section outlines SA Power Networks’ best endeavours approach to addressing the largest drivers of reliability impacts, excluding equipment failures, which are addressed through more targeted and increased asset replacement investment as described in section 3.3.

5.2.1 Weather

There are many weather-related impacts on our network performance.

Vegetation represents 18% of total USAIDI and the trend is escalating

Vegetation-related outages are increasing due to an expanding vegetation canopy across the network as vegetation continues to grow. SA Power Networks undertakes vegetation clearance in accordance with its obligations under the *Electricity Act*; however, in **non-bushfire risk areas (NBFRA)**, we are not permitted to clear vegetation directly above powerlines. As a result, ‘out-of-zone’ vegetation has become a significant cause of vegetation-related outages.

To mitigate these outages, SA Power Networks installs covered conductor, or applies line covering to existing bare conductor, in locations where vegetation contact is known to cause unplanned outages. SA Power Networks has also previously undertaken targeted programs to remove problem vegetation in high-risk areas.

These challenges are being compounded by broader policy and planning settings. The Urban Greening Strategy for Metropolitan Adelaide includes a long-term objective to expand the city’s tree canopy, increasing the volume of vegetation in proximity to the network. In addition, planning regulation changes introduced in May 2024 have further limited the removal of vegetation in metropolitan areas. Together, these factors have made it increasingly difficult for SA Power Networks to negotiate the removal of out-of-zone vegetation.

Accordingly, it is reasonable to expect that the current worsening trend in vegetation-related outages will continue without further intervention. In response, SA Power Networks began scaling up its line covering program in late 2025 to help address this trend.

Lightning represents 11% of total USAIDI and the trend is stable

As noted earlier, since 2008 SA Power Networks has continued a program to upgrade significant sections of the high-voltage network in known lightning-prone areas by replacing porcelain insulators susceptible to lightning damage with more lightning-resistant resin-based insulators. These locations have generally been identified based on previous lightning-related damage to porcelain insulators. Resin-based insulators were the standard installed prior to 2025; however, SA Power Networks has now transitioned to silicone insulators, which are less susceptible to insulator pollution.

In addition to this proactive program, SA Power Networks’ standard reactive practice is to replace all porcelain insulators on a pole with lightning-resistant insulators where an insulator failure has occurred due to lightning. This program has resulted in a significant reduction in lightning-related USAIDI and has improved reliability for customers served by the mitigated sections of the network.

Insulator Pollution represents 4% of total USAIDI and the trend is escalating

Insulator pollution occurs when contaminants such as salt, dust, agricultural residue and other airborne particles accumulate on the surface of network insulators. Under certain weather conditions, particularly moist, humid, foggy or dewy conditions, these contaminants can become conductive, allowing electrical current to track across the insulator surface rather than remaining isolated as intended. This can result in flashovers, where electricity arcs across the insulator, causing momentary or sustained supply interruptions. In more severe cases, pollution-related tracking can also lead to equipment damage, accelerated asset deterioration and fire starts, particularly where insulator materials are vulnerable to heat damage.

The risk is heightened in areas exposed to coastal salt spray, dryland farming activity and other environmental conditions that accelerate contamination build-up. These impacts have reduced network reliability, increased operational response requirements, and elevated safety and bushfire risk during periods of high fire danger.

Over the 2024–25 and 2025–26 summers, SA Power Networks experienced a significant number of outages related to insulator pollution. Based on current understanding, this appears to have been driven by a combination of climatic change, with longer periods without rain, rising sea temperatures, and the ongoing effects of the previous year’s pollution event.

These outages have been a major contributor to the poor performance of rural long feeders. In response to these events, SA Power Networks undertook an extensive program of proactive and reactive insulator washing.

Given the significant reliability impacts associated with insulator pollution, SA Power Networks developed an **Insulator Pollution Mitigation Plan** in 2025, which was further refined in 2026 following extensive

investigations. A broad program of targeted activities (set out below) is now underway across the network to improve reliability performance and reduce risk in affected areas. This program combines feeder automation, powerline works, substation maintenance and equipment replacement, with a strong focus on delivering practical improvements ahead of the 2026–27 summer period.

Feeder automation program

A key component of the mitigation plan is the deployment of feeder automation to reduce the severity and duration of interruptions where faults occur. Feeder automation is being deployed across multiple feeders connected to the Ardrossan West and Dalrymple transmission connection points on Yorke Peninsula.

Powerline program

The powerline component of the program is focused primarily on the 33kV network, where 80–90% of customer impacts over the last summer was attributable to 33kV insulator flashovers. The remaining impact arose from flashovers on the 19kV SWER network.

33kV powerlines

The 33 kV feeders have been prioritised based on:

- the largest number of customers impacted;
- number of fire starts;
- number of sustained interruptions; and
- number of momentary interruptions.

Targeted crossarm rebuilds will be undertaken across four 33kV feeders, including the replacement of hundreds of post-top insulators across 70+ poles.

As a further measure, a helicopter will be deployed to spray silicone across seven 33kV feeders, treating 2,500 pole tops. This work is scheduled to commence July 2026.

33kV Insulator remediation

To reduce the impacts of insulator pollution, a range of remediation options has been assessed, including:

- washing insulators with water;
- applying silicone coating to affected insulators;
- replacing polymer insulators with silicone units; and
- undertaking pole-top rebuilds using new crossarms and high-pollution-rated insulators.

A comprehensive cost–benefit analysis has been completed to determine the most appropriate treatment for each location, taking into account both network benefit and deliverability, including material availability and resourcing constraints.

11kV and 33kV Insulator replacement

Investigations into recent pollution-related incidents identified cycloaliphatic polymer pin insulators, installed between 2008 and 2025 as part of the network hardening program for lightning resilience, as the predominant cause of outages and fire starts.

Unlike porcelain, cycloaliphatic polymer can melt and burn when exposed to high temperatures including fault current energy, as can be seen in Figure 8. This increases the risk of both fire starts and subsequent flashovers, making replacement and remediation of these insulators a priority in the highest-risk parts of the network.

Figure 8: Cycloaliphatic polymer insulator affected by insulator pollution



Cycloaliphatic polymer pin insulators are no longer installed on the network, having been replaced by silicone pin insulators as the new standard.

Porcelain and cycloaliphatic pin insulators across 20+ feeders will be replaced with silicone pin insulators. This will deliver more than 8,000 silicone insulators across approximately 2,850 poles.

Pole top equipment will be replaced as required during the insulator replacements. This approach aligns with broader industry practice, with silicone-based insulators offering hydrophobic properties that are far more effective in reducing pollution-related flashovers.

SWER program

The SWER program of work extends across 45 SWER lines. Of these:

- 30 SWER lines are planned for silicone spraying, covering 895 pole tops; and
- 15 SWER lines will have pin insulators replaced with silicone pin insulators, impacting 848 poles.

Substation program

At substations, the program includes washing insulators at 44 sites, comprising seven ElectraNet connection points and 37 distribution substations.

Substation equipment replacement works are also being prioritised, including:

- stand-off insulator replacements at 15 operational locations;
- two-way fuse base replacements at six locations; and
- horizontal LSDF replacements at one location.

Stakeholder engagement

Delivery of the Insulator Pollution Mitigation Plan also includes a strong focus on community and stakeholder engagement. A large amount of the work will require planned power outages to enable the work to be undertaken safely. We recognise this will further impact customers who have already experienced very poor reliability.

The stakeholder engagement component is intended to build customer confidence in the work underway, improve understanding of why the program is required, and minimise the impact of planned interruptions necessary to complete the works.

The Insulator Pollution Mitigation Plan represents a major portfolio of work which has been prioritised within SA Power Networks broader capital works program and represents a significant collaborative effort across SA Power Networks.

5.2.1 No cause found

No Cause found represents 18% of total USAIDIn and the trend is declining

Where a HV outage occurs and no cause is initially identified, our Network Reliability Team investigates whether protection has operated as designed. If it has, the team undertakes further investigation to determine the cause of the initial interruption. This typically involves an immediate follow-up inspection of the line, which is reasonably effective in identifying the cause before another outage occurs.

We also proactively patrol lines following reclose events that meet specific criteria, to identify potential causes and prevent a sustained outage. These practices reduce outage impacts by around 5 SAIDI minutes per year. In 2026, we increased the number of Reliability Patrol Officers from one to three to support these patrols.

SA Power Networks also periodically reviews the performance of individual protection devices. Where a device has recorded a high number of no cause found events, protection settings may be adjusted or equipment upgraded to help.

5.2.2 Third party

Third party – animals (bats, birds, possums) account for 8% of total USAIDIn and the trend declining

Over the past regulatory period, third-party animal-related causes increased, mainly due to growth in wildlife populations surrounding, and coming into contact with the network.

The main contributor has been the **grey-headed flying fox (GHFF)**, Australia’s largest bat and one of the largest in the world. It is a protected species and is listed as vulnerable. A significant group of flying foxes arrived from the eastern states in 2010 and established a permanent colony in the Adelaide Botanic Gardens near the Adelaide Zoo. Since then, the population has grown from around 10,000 to more than 50,000. This increase has coincided with a rise in power outages across the network. Prior to 2010, there was no GHFF colony in South Australia. The size of the colony fluctuates according to food availability and ambient temperatures.

GHFFs cause outages when they come into contact with powerlines or pole-top equipment such as insulators, transformers, switches, and lightning arresters.

The GHFFs are most active at night while foraging for food, including nectar, pollen, and fruit. They typically travel 20–30 km from their colony, covering much of metropolitan Adelaide and nearby horticultural areas. As they do not follow fixed flight paths and instead move according to food sources, their impact is widespread and difficult to predict or target. Outages are most common in January and February, when juvenile bats, which have shorter flight ranges, land more frequently on pole-top infrastructure.

The random nature of GHFF-related outages across the extensive Adelaide distribution network makes it challenging to significantly reduce their occurrence.

Over the past two years, SA Power Networks has significantly increased the installation of animal guards, reducing animal-related incidents and delivering a more than 40% reduction in unplanned SAIDI associated with GHFF high-voltage outages, as can be seen in the following figures.

Figure 9: Animal guards installed v animal incidents

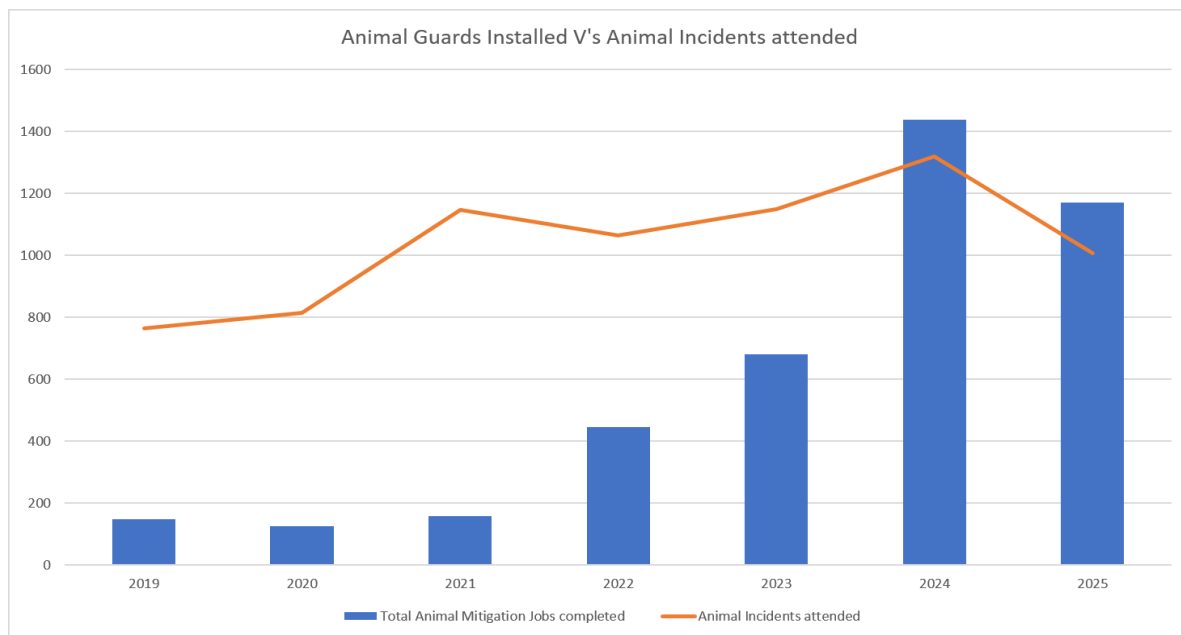
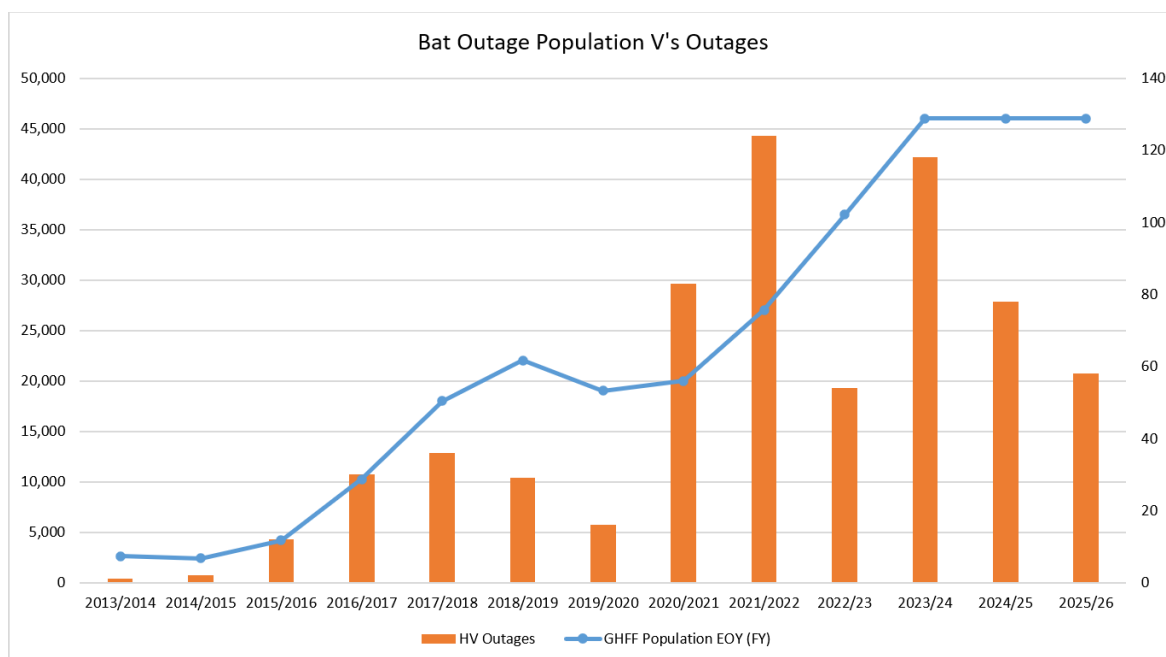


Figure 10: GHFF population versus outages



Our efforts remain focused on balancing the protection of this vulnerable species with maintaining reliable electricity supply for our customers.

We also install guards to prevent birds and other animals, such as possums, from bridging between active conductors and earth, for example from the conductor to the crossarm. These guards are installed in known problem areas and on feeders that experience repeated animal-related outages.

5.2.3 CBD reliability

For the purpose of reporting, the ‘CBD’ is the Adelaide Central Business District which includes significant commercial, government, residential, cultural and entertainment customers and development. Reliability performance targets for the CBD are established by ESCoSA in the EDC.

Since 2017–18, our performance against CBD reliability targets has been varied. While we have met the targets in some years, we have fallen short in others. Overall, CBD reliability has gradually declined, primarily due to underground cable failures and faults. This is largely because a significant portion of the high-voltage cables in the CBD are now over 50 years old. A substantial part of the CBD network is expected to reach the end of its service life within the next 20 years.

ESCoSA expects SA Power Networks to invest appropriately to meet the minimum network performance standards for CBD feeders. Although the AER did not approve all our proposed expenditure for CBD reliability improvements, we plan to prioritise planned cable replacements, as this is the main factor impacting CBD reliability. Even with this focus, it is unlikely we will meet the CBD reliability target by 2029–30. As in recent years, we expect performance to fluctuate throughout the 2025–30 RCP, with some years meeting the target and others falling short.

Furthermore, the AER did not allocate specific funding for feeder automation in the CBD, instead it provided an overall allowance for maintaining reliability across the entire network where DFA can be implemented where it delivers the greatest economic benefit for customers. Given the significant reduction in the Value of Customer Reliability for business and commercial customers, we anticipate fewer DFA projects will be undertaken in the CBD during the 2025–30 RCP.

Cable faults in the CBD are mostly seen on paper insulated lead cables (**PILC**) with aluminium conductor. Modelling of cable type, age, failure history and other fault contributing factors, has been undertaken to generate a probability of failure for each cable in the CBD. This data along with known consequence information (such as customers effected by an outage), is used to take a risk-based approach to a proactive replacement program of cable within the CBD.

The CBD Program Steering Committee meets regularly to monitor the reliability and safety performance objectives of the CBD. A key focus of the committee is to provide governance and oversight of the CBD cable replacement program, which plays a critical role in meeting ESCoSA reliability targets and maintaining safety performance standards.

6. Emerging trends impacting network reliability

As explained in Section 4, improving reliability performance typically takes time. Therefore, it is important for SA Power Networks to monitor emerging trends so that rectification measures can be implemented as early as possible.

6.1 Decline in reliability performance of Long Rural feeders

We have observed a material decline in the USAIDI and supply restoration performance of long rural feeders since 2023–24. The major causes contributing to the increase in USAIDI are as follows:

1. An increase in weather related interruptions which is caused by the significant increase in insulator pollution and the impacts of lightning¹⁶ ; and
2. The decline in the performance of 19kV SWER feeders. Sectionalisers are not operating due to the feed in voltage from distributed energy resources (e.g. solar pv).

¹⁶ The distribution system was initially designed for a low isokeraunic levels (i.e. South Australia historic lightning levels were low)

Figure 11: Long rural performance by interruption cause (USAIDIn)

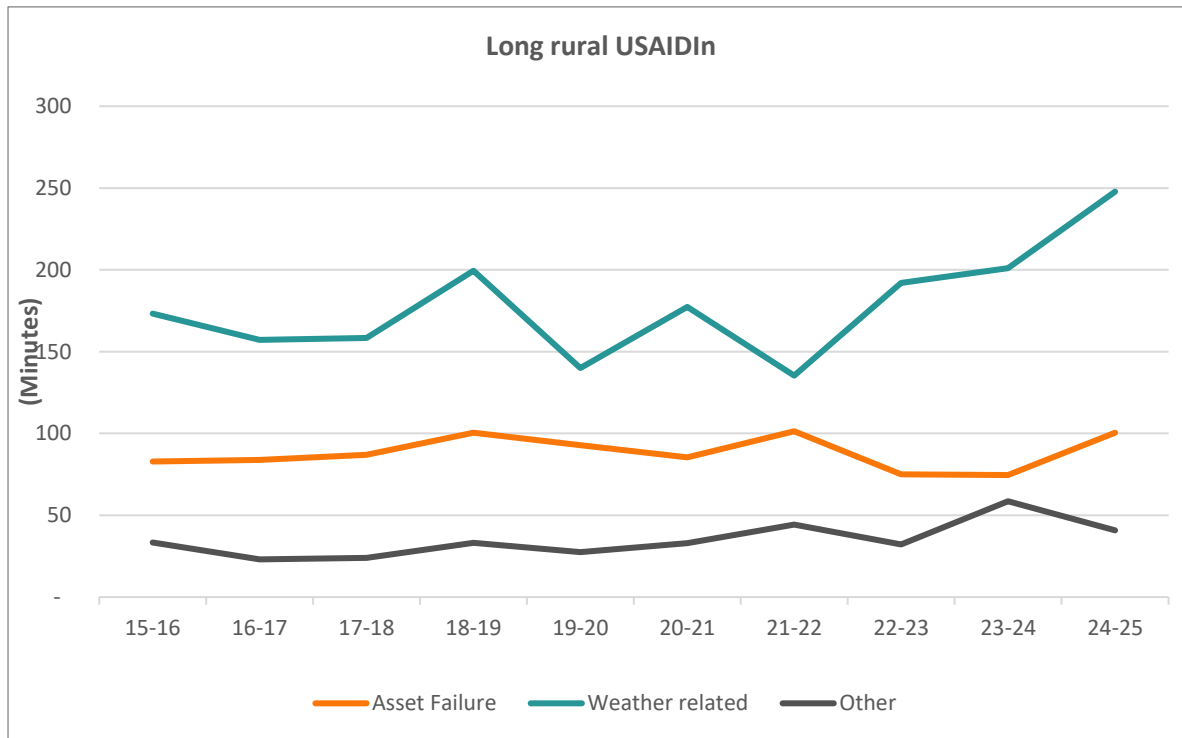
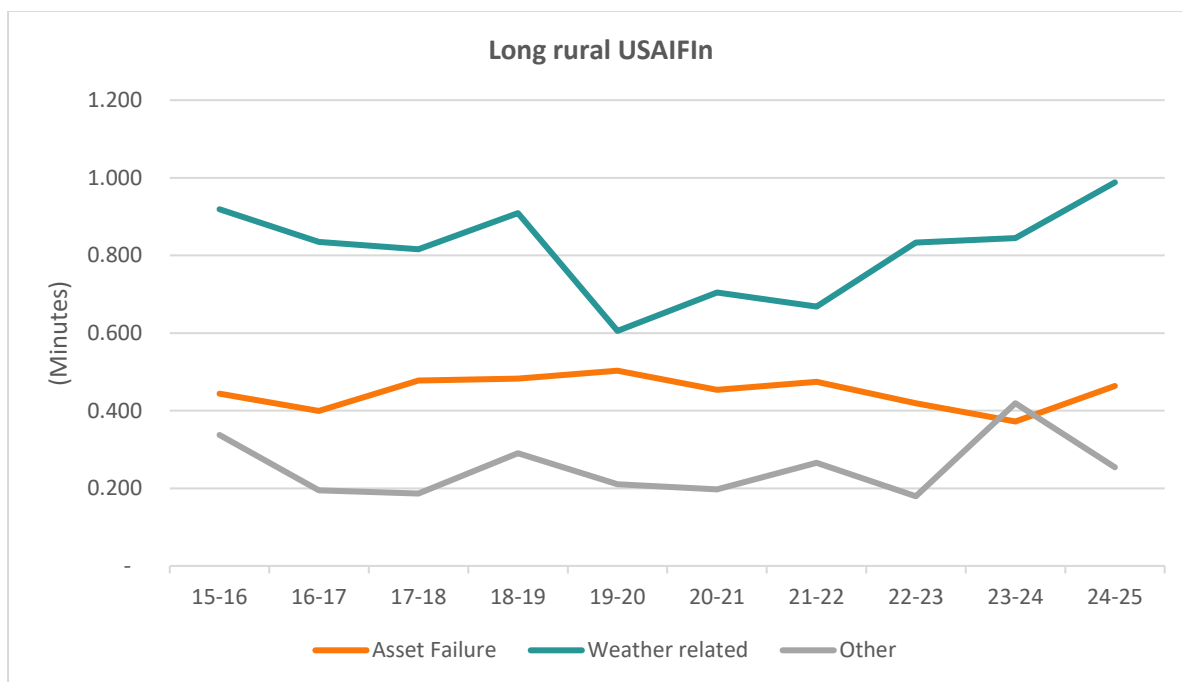


Figure 12: Long rural performance by interruption cause (USAIFIn)



6.2 Decline in 19kV SWER performance

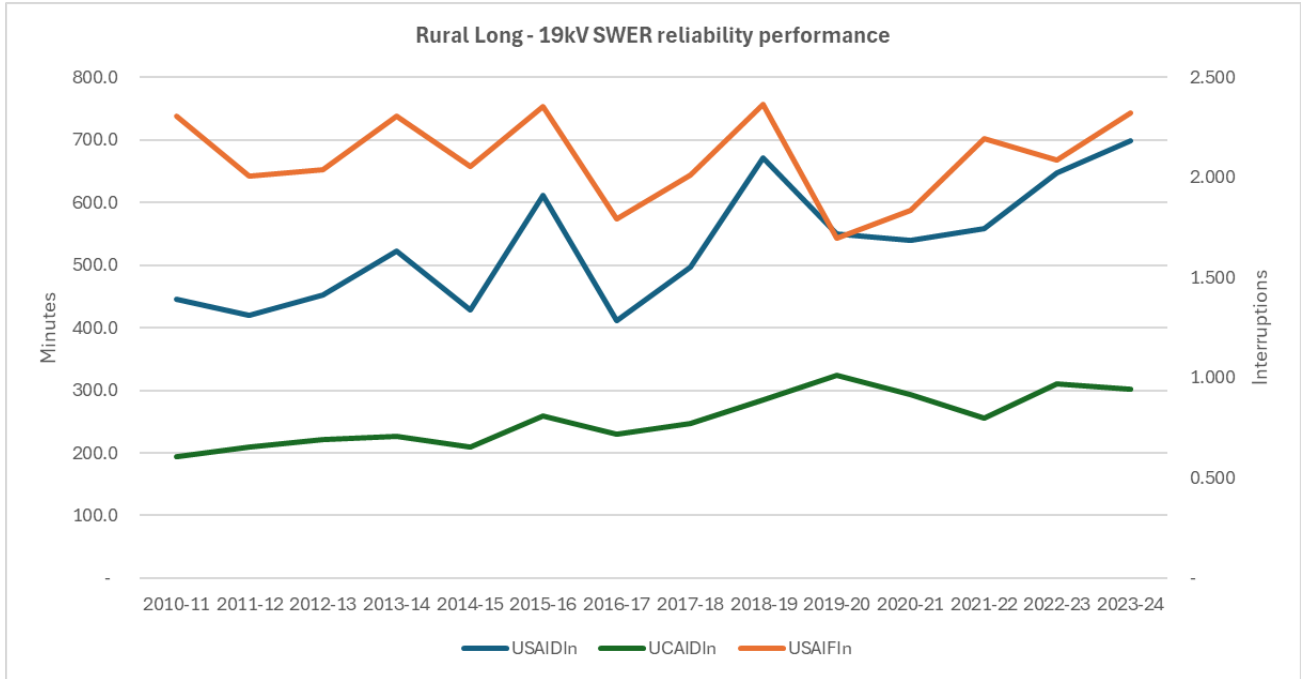
Figure 13 below highlights the decline in both USAIDIn and UCAIDIn in Rural Long 19kV SWER feeders since 2010–11. The decline is due to several factors which include:

1. The proliferation of Solar PV which results in our sectionalisers being ineffective during daylight hours which leads to extended timeframes to locate and repair the fault on long lines;

2. Ageing of the 19kV SWER network which is now 50-60 years old; and
3. Operational and safety factors which are delaying the restoration of supply.

It highlights that the percentage of customers affected by outages has remained consistent with a decline in UCAIDIn and consequently USAIDIn.

Figure 13: Long rural 19V SWER feeder reliability performance (excluding MEDs)



Sectionalisers and Solar PV

Sectionalisers are used to mitigate the impact of outages, as it limits the number of customers affected by a fault on the feeder to those customers downstream of the sectionaliser, with other customers supplied by the feeder seeing a momentary interruption. For a sectionaliser to work it must have zero voltage on the downstream side of the recloser. However, downstream Solar PV installations are preventing the voltage from decreasing to zero¹⁷, so the sectionaliser no longer works. This results in longer patrol times to locate and then repair the fault, as the whole feeder must be patrolled instead of just the section downstream of the sectionaliser.

We have commenced replacing sectionalisers with reclosers, prioritising high USADI feeders. We plan to replace 100 sectionalisers in 2025 and a further 80 in 2026. This should over time improve our Long Rural USAIDIn and the restoration of supply performance.

Operational and other factors

There are a number of operational and other factors which are delaying restoring customer supplies on 19kV SWER feeders, which include:

- Greater damage to infrastructure requiring more work, and consequently longer to restore supply.
- Full patrol of the feeder versus previously part patrols, mainly during the fire danger season, to prevent fire starts.

¹⁷ Inverters on Solar PV systems are supposed to disconnect from the distribution network within 2 seconds of seeing no supply, however, it is taking around five seconds for inverters to disconnect. This longer time frame results in the sectionaliser failing to open due to voltage being present. It is unclear if this is a non-compliance with our requirements or because of other Solar systems giving the appearance of the system supply still being available.

- Customers locking gates/access points or requiring phone calls prior to enter, which is extending the duration of patrols and consequently delaying restoring customers electricity supply.
- Installation of SCADA on SWER feeders reclosers which identifies immediately when supply is lost. Previously, customers would typically wait until the morning to advise that they had lost electricity supply (i.e. crews were already available to respond). The mobilisation of crews to respond delays restoration time compared to crews being at work and available to respond.

In 2024 we established a project team to investigate the cause of our declining rural long (SWER) feeder performance. To address this decline we are implementing the following measures over 2025 and 2026:

- Replacing 180 SWER sectionalisers with reclosers;
- Installing SWER fault indicators at 776 locations;
- Installing lightning resilient insulators on 3,400 poles;
- Installing 11kV mid-line reclosers at 27 locations; and
- Installing 33kV mid-line reclosers at 10 locations (in 2026).

For the 2025-30 period, the AER has approved a reliability allowance for regional customers under the 'Worst Served Customers' program which will improve some rural long performance outcomes. This program recognises that improving reliability for regional customers is often un-economic under STPIS.

The implementation of improvement measures will take time due to the vastness of the SWER network and the limited availability of resources. Incremental improvements should be seen over 2025–26 with a more material improvement seen from 2026–27.

7. Demonstration of Best Endeavours

The EDC requires SA Power Networks to use **best endeavours** to achieve the customer service and reliability standards set out in the EDC. **Best endeavours** means to act in good faith and use all reasonable efforts, skill and resources.

7.1 How SA Power Networks demonstrates best endeavours

SA Power Networks demonstrates best endeavours by identifying the applicable EDC obligations, allocating accountable personnel, deploying appropriate operational and technical resources, monitoring performance against the relevant standards, escalating emerging risks, and implementing corrective actions where required.

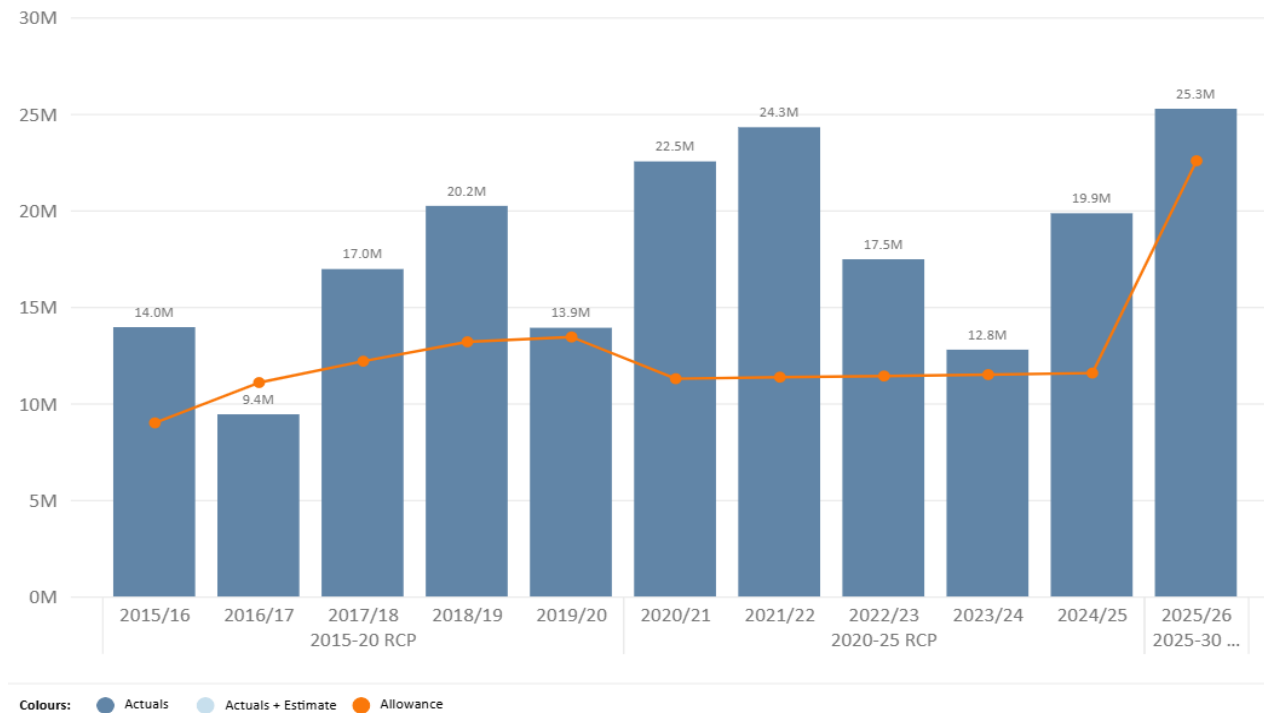
We seek to ensure that our actions are undertaken in good faith and are reasonable and proportionate in the circumstances. This is evidenced by our plans, operational records, risk assessments, decision papers, resourcing records and performance reporting.

Best endeavours does not require SA Power Networks to guarantee an outcome at any cost. Rather, it requires us to do all that is reasonably able to be done in the circumstances to achieve the relevant target. Where a target is not met, the relevant question is whether SA Power Networks nonetheless took all reasonable steps, using appropriate skill and resources, to seek to achieve that target.

One indicator of best endeavours is the level of resources and expenditure SA Power Networks commits to maintaining reliability. The AER's Distribution Determination includes an allowance intended to maintain SA Power Networks' historic reliability performance. Figure 14 shows that we are committing materially greater resources than provided for in that allowance in order to maintain reliability. However, despite this increased expenditure, reliability performance in some feeder categories, including Long Rural feeders, has continued

to decline. This indicates that increased expenditure alone does not guarantee improved reliability outcomes, particularly where broader network, geographic or operational factors are affecting performance.

Figure 14: SA Power Networks – Reliability expenditure versus allowance



As noted above, because the relevant obligation is to use best endeavours, SA Power Networks may still comply with a service standard obligation even where the target is not achieved, provided it can demonstrate that it has used best endeavours in seeking to achieve that target.

SA Power Networks monitors performance against the EDC customer service and reliability standards on both a daily and monthly basis. Where monitoring indicates that a customer service target is unlikely to be achieved, it is often possible to take corrective action within the remaining period of the year and improve performance sufficiently to meet the target. By contrast, it is generally not feasible to reverse underperformance against a reliability measure within the balance of the year.

This is because underperformance in customer service measures can often be addressed by increasing operational focus or allocating additional resources in the short term. Reliability performance, however, is not typically improved simply by adding resources. Where poor reliability performance is driven by systemic issues, improvement often requires a multi-year program of analysis, engineering assessment, planning and works delivery.

Remediation to improve reliability may involve several steps, including:

- analysing faults and interruption data to identify the causes of poor performance and assess potential remedies;
- investigating new equipment, technologies or methods to address systemic issues;
- trialing alternative solutions;
- designing the required works, which may involve replacing poles or equipment, restringing sections of line, or determining the most effective location for network improvements;
- planning and scheduling the work;

- procuring materials and equipment; and
- arranging outages, notifying customers and completing the works.

In addition, reliability improvement must be delivered at the level of individual feeders. Accordingly, achieving a material improvement in overall reliability requires improvements across many feeders. SA Power Networks' distribution network includes more than 1,500 high voltage feeders, which further illustrates the scale and complexity of the task.

7.2 Variation in reliability feeder performance over time

SA Power Networks uses a 10-year Target Setting Period (TSP) as the basis for assessing the historical reliability performance used to establish the EDC reliability targets. A 10-year period provides a sufficiently long timeframe to capture normal year-to-year variation in network performance across a range of operating conditions, while reducing the influence of unusually good or poor individual years. It therefore provides a more stable and representative basis for reliability target setting.

Table 12 and Table 13 below illustrate the variation in reliability performance over the 10-year TSP used to establish the EDC reliability targets.

Table 12 - USAIDIn and USAIFIn EDC Targets and variation in performance during TSP

	USAIDIn					USAIFIn				
	CBD	Urban	Short Rural	Long Rural	Dist Nwk	CBD	Urban	Short Rural	Long Rural	Dist Nwk
EDC Target	15	110	200	290		0.15	1.15	1.65	1.75	
Average	16	108	199	289	150	0.15	1.17	1.63	1.75	1.32
Maximum	44	132	283	351	181	0.39	1.39	2.21	2.28	1.65
Minimum	4	94	143	239	124	0.04	0.95	1.19	1.43	1.12
RT	20	125	220	330	175	0.20	1.35	1.85	2.10	1.50
Exceeded RT (times)	1	1	2	3	1	1	2	2	2	2

Table 13 - Restoration of supply EDC targets and variation in performance during TSP

	Restoration of Supply (1 st Target)				Restoration of Supply (2 nd Target)			
	CBD ≥ 1 Hr	Urban > 2 Hrs	Short Rural > 3 Hrs	Long Rural > 4 Hrs	CBD > 2 Hrs	Urban > 3 Hrs	Short Rural > 5 Hrs	Long Rural > 7 Hrs
EDC Target	11%	27%	27%	30%	4%	11%	8%	10%
Average	10.6%	27.1%	27.3%	30.0%	4.5%	11.1%	8.1%	9.5%
Maximum	29.5%	33.9%	46.1%	36.4%	16.9%	13.4%	10.1%	13.9%
Minimum	3.4%	22.9%	21.5%	20.6%	0.6%	7.9%	5.0%	6.3%
RT	13.5%	29.5%	29.5%	32.5%	6.5%	13.5%	10.5%	12.5%
Exceeded RT (times)	3	3	1	3	1	0	0	1

Table 12 shows the EDC targets for USAIDIn and USAIFIn, together with the average, maximum and minimum annual performance recorded during the TSP. Table 13 provides the same comparison for the restoration of supply measures. This data demonstrates that reliability performance varied materially from year to year during the TSP across a number of feeder categories and measures. This historical variability is relevant when assessing compliance with a best endeavours obligation, because it shows that annual reliability outcomes can fluctuate significantly even over the period used to derive the EDC targets.

For example, for Long Rural USAIDIn, annual performance during the TSP ranged from 239 minutes at the low end to 351 minutes at the high end, compared with an average of 289 minutes. For Long Rural USAIFIn, annual performance ranged from 1.43 to 2.28, compared with an average of 1.75. This illustrates the extent to which reliability outcomes for a given feeder category may vary over time. Accordingly, where a reliability outcome in a particular year is worse than the target, that result should be assessed in the context of both the historical variability of the measure and the actions taken by SA Power Networks to improve performance.

SA Power Networks has a daily monitoring system in place that analyses reliability performance at the feeder level and identifies feeders requiring improvement. We have developed a range of methods to improve reliability where performance has deteriorated or where improvement is required across a feeder category. We also establish dedicated project teams to investigate specific issues and assess possible interventions where there has been sustained deterioration in performance, including in categories such as CBD and Long Rural feeders. These activities inform the development and implementation of work plans aimed at improving reliability and achieving the applicable reliability standards.

These monitoring, investigation and remediation activities form part of the way SA Power Networks applies reasonable efforts, skill and resources in seeking to achieve the EDC reliability standards.

A. Risk management

SA Power Networks has established robust risk management principles, policies, rules, practices and processes. Our Risk Management Directive outlines the principles, structure and approach to risk management across SA Power Networks and Enerven and is aligned with the risk management principles of ISO 31000.

Risks are identified, assessed, managed, mitigated and monitored through our enterprise Risk Management Framework, which provides the foundation for effective risk control. The framework supports the identification and management of strategic risks that could have a material impact on the organisation.

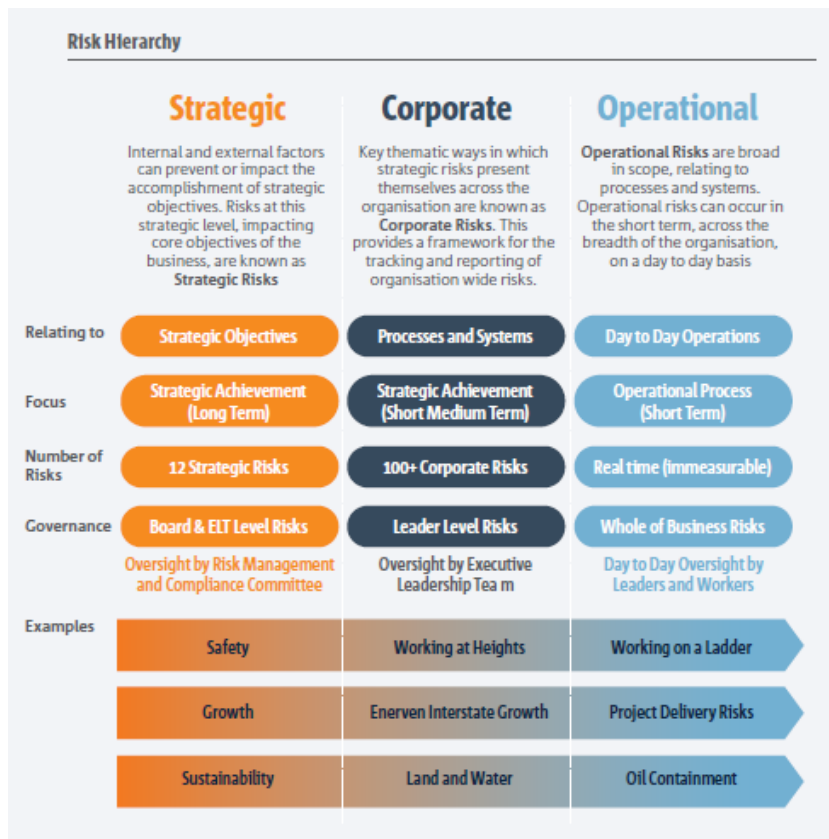
We apply a risk management approach to all business activities to ensure the organisation is not exposed to unacceptable levels of risk, while maximising opportunities where appropriate.

Oversight of the organisation’s risk profile is provided by the Risk Management and Compliance Committee, which monitors the policies, processes and procedures used to identify, report and manage significant business risks.

The Risk Management Framework also provides the tools used to identify, analyse, evaluate and treat risk, including defined tables for likelihood, consequence and risk rating.

Our approach to risk management begins with our highest priority: the safety of our people and the public. This is reflected in the Risk Appetite Statement, which sets out the Board’s explicit appetite and tolerance for risk and guides key management decisions.

The corporate Risk Register provides a transparent record of the material risks facing the organisation. It defines the strategic risks facing the business and links them to related corporate and operational risks through a parent–child risk relationship model across three levels: strategic, corporate and operational.



Organisational resilience

SA Power Networks maintains an overarching Organisational Resilience Policy and Framework designed to strengthen the organisation's ability to respond to both anticipated and unexpected disruptions. It supports effective response and recovery by aligning with existing corporate strategies and management systems.

The Organisational Resilience Framework brings together key resilience disciplines within a cohesive structure comprising policy, directive and operational documents. It manages the interdependencies between:

- Risk management
- Crisis and emergency management
- Business continuity management
- IT protection and recovery

Risk management directive

SA Power Networks' approved Risk Management Directive, states, in part:

SA Power Networks will apply a risk management approach to all business activities to ensure that the organisation maximises opportunities, while not exposing the business to unacceptable levels of risk.

Under this Directive, risk management considerations are incorporated into the planning, design, construction and operational phases of all activities. Risk management is a fundamental component of business operations and a shared responsibility of all employees.

Part of managing risk includes maintaining appropriate insurance arrangements to provide financial protection against potential losses if specific risks materialise. To support implementation of the Directive, the Risk Management Framework and Risk Appetite Statement have been developed and communicated across the business.

Risk appetite statement

SA Power Networks has formally defined its risk appetite through its approved Risk Appetite Statement. This statement sets out the level of risk the organisation is willing to accept and provides guidance from the Board to employees across the organisation.

The statement describes risk appetite and tolerance in relation to:

- Strategic decisions
- Financial and commercial decisions
- Operational decisions, including decisions affecting the environment and the health and safety of our people, customers and other stakeholders impacted by our operations

Managing risk

The electricity network carries inherent risks, including the potential to ignite a major bushfire, cause widespread property damage, and result in injury or loss of life to employees or members of the public. This section outlines the principal risks SA Power Networks manages in delivering services to customers.

Risk is assessed in terms of both the likelihood of an event occurring and the consequence if it does occur. Risks are assessed at both:

- the corporate level through a top-down approach; and
- the individual asset level through a bottom-up approach.

Managing external risks

SA Power Networks applies a structured methodology for identifying, assessing and monitoring external risks on an ongoing basis. Identified risks are recorded in the relevant risk registers, which document how they are managed and assign accountability to risk owners.

Managing operational risks

Operational risks are mitigated through operational procedures, standards and contingency planning. This includes the preparation of detailed contingency plans for all credible critical events that could lead to undesirable outcomes such as plant damage, loss of supply, or risks to public safety.

Managing asset risk

Asset risks are managed by understanding the impact of asset failure on customers and stakeholders, and by applying sound asset management practices throughout the asset life cycle.

Asset defects identified through inspection and condition monitoring processes are assessed for risk, and the estimated cost to repair or replace the defect is determined through the Value and Visibility process. This process is used to support prioritisation of resources across work types and to compare the relative risk and cost of proposed works in day-to-day decision-making.