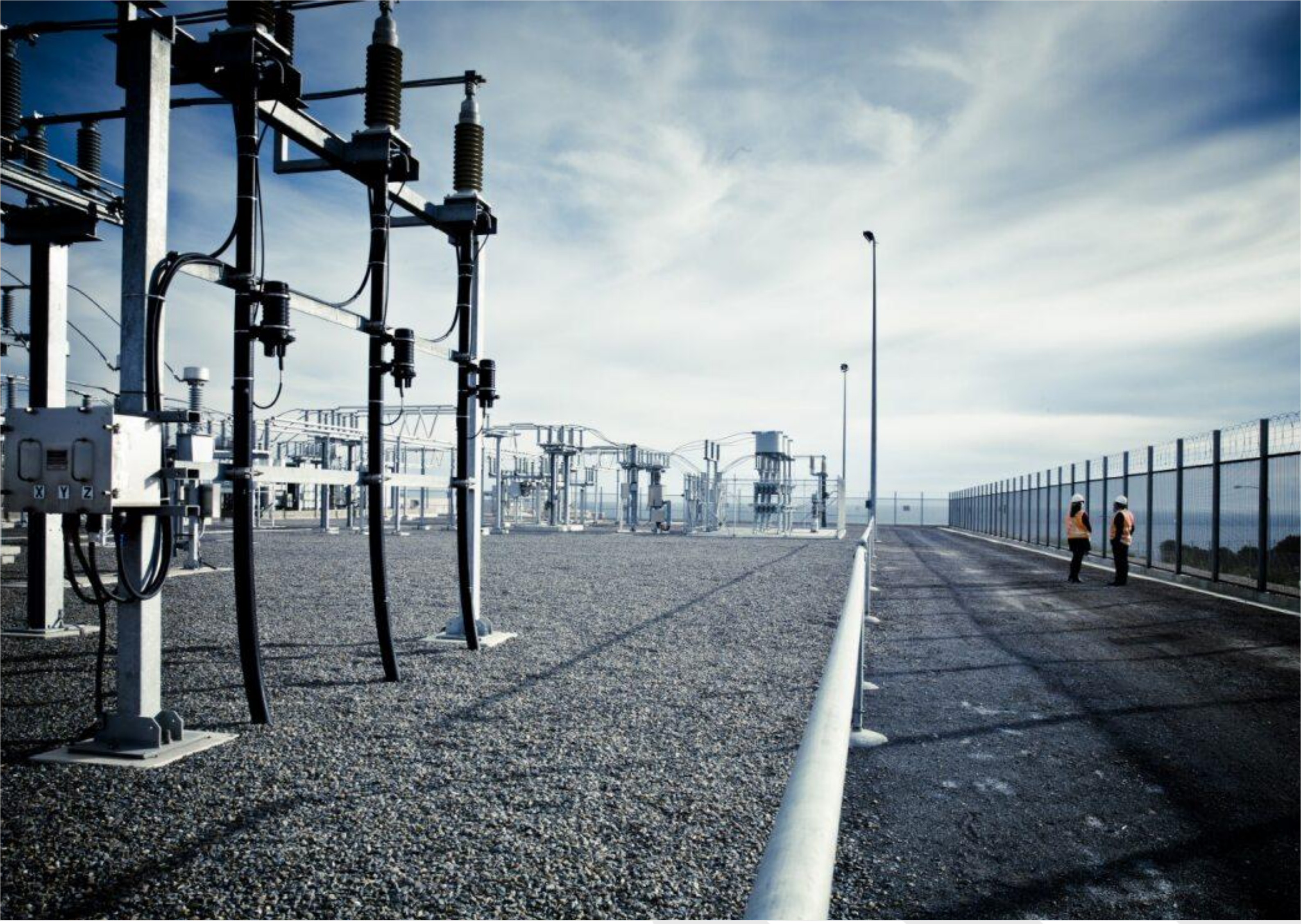

Business case: Augex Network Safety

2025-2030 Regulatory Proposal

January 2024

Supporting document 5.8.5

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AER	Australian Energy Regulator
Augex	Augmentation expenditure
BFRM	Bushfire Risk Management
Capex	Capital expenditure
CB	Circuit breaker
CBD	Central Business District
DER	Distributed energy resources
ENA	Energy Networks Australia
ESCoSA	Essential Services Commission of South Australia
HV	High Voltage
ICT	Information and Communication Technology
LV	Low voltage
NEL	National Electricity Law
NER	National Electricity Rules
NPV	Net present value
Opex	Operating expenditure
OTR	Office of the Technical Regulator
RCP	Regulatory Control Period
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan

1 About this document

1.1 Purpose

This document provides a business case to support forecast expenditure for the 2025-30 Regulatory Control Period (**RCP**) for SA Power Networks' safety related augex program, which comprises one input to our overall capital expenditure (**capex**) on network augmentation (**augex**). This safety component includes expenditure necessary to maintain the safety of our network (excluding repex) for our workforce and the general public.

This expenditure includes upgrades to network protection and earthing systems as a result of changes (e.g. load growth) within the network, but excludes bushfire safety (expenditure for our bushfire management programs justified in a separate business case: *5.6.1 Bushfire Risk Management Business Case)*. The following programs of work are included within the network safety related augex program:

- Substation Lighting Program;
- Substation Security and Fencing Program;
- Substation Infrastructure – Earth Systems Program;
- CBD Site Safety Program; and
- Protection Systems Compliance Program.

1.2 Expenditure category

- Network capex: augmentation

1.3 Related documents

Table 1: Related documents

Ref	Title	Author	Version / date
5.4.1	Augmentation Expenditure (Augex) Forecasting Approach	SAPN	

2 Executive summary

This business case recommends $42.7M[1] in safety augmentation capital expenditure for the 2025 – 30 RCP across five programs of work.

2.1 Substation Lighting Program (AUG019)

The substation lighting program commenced in 2001 and is focused on improving the indoor emergency lighting at substation sites. The program was initiated to address safety concerns following an incident that occurred at a CBD substation where a power failure of the local lights and power circuits resulted in workers being left in the vicinity of energised equipment with no visibility. A continuation of this program in the 2025-30 RCP is proposed.

Our recommendation is to invest $0.4M on the Substation Lighting Program – this spend is consistent with expenditure in the 2020-25 RCP.

1 Represents the capex in $m June 2022, excluding corporate overheads.

2.2 Substation Security and Fencing Program (AUG020)

We have an ongoing risk-based program of substation perimeter fence augmentation and video surveillance. A continuation of this program in the 2025-30 RCP is proposed. Zone substations are hazardous environments, and SA Power Networks has an express regulatory obligation to prevent unauthorised access. Failure to do so can result in serious injury, permanent disability or death.

Energy Networks Australia (**ENA**) have published guidelines for industry best practice for the security of zone substations. Approximately 20% of our major metro substations fail to meet these minimum requirements, and instead consist of a simple chain mesh link fence that can be broken into using basic tools. Break-ins to zone substations continue to occur, largely motivated by copper theft. Risks of break-ins include safety of the intruder who may be exposed to dangerous high voltages. Invariably, once the security has been compromised there is free and uninhibited access for any inquisitive member of the public, including children. Furthermore, copper theft may disable our protection systems and expose the community to the risk of fatal electric shock.

This business case recommends investing $12.9M on the Substation Security and Fencing Program to continue this program in the 2025-30 RCP. This spend is consistent with expenditure in the 2020-25 RCP.

2.3 Substation Infrastructure – Earth Systems Program (AUG021)

We have an established earth grid remediation and test program to address known issues and monitor performance of substation earthing systems.

Lack of an effective substation earth grid can pose a significant threat to human safety and protection equipment integrity during network earth fault conditions. The dangers of Earth Potential Rise and associated step and touch potentials are not only a risk within substation fences, but also in nearby publicly accessible areas and adjacent telecommunication infrastructure.

We recommend investing $6.3M on the Substation Earthing Systems program – this is a small increase of $0.5M to accommodate new cost sharing agreements for ElectraNet managed earth grid testing at shared sites[2], while maintaining our existing testing program (20 sites per year, with a 15-year cycle to test all sites). A continuation of this program will maintain current safety standards with respect to earth grid safety by addressing known issues and continuing to monitor the performance of substation earthing systems.

2.4 CBD Site Safety Program (AUG024)

The Central Business District (**CBD**) Site Safety program, which encompasses the 33kV CBD substation conversion to 11kV Project, addresses safety and compliance risks at CBD substations due to inadequate electrical clearances, poor access within the substation, absence of emergency exits and/or inadequate ventilation. These risks, and hence the program, are not primarily driven by asset condition.

The primary objective of this program is to ensure we mitigate safety risk, whilst also remaining compliant with regulatory obligations / requirements relating to operations, and our distribution licences.[3]

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2 Additional funding is now required to contribute to shared management of earth testing at shared sites, where historically, ElectraNet had borne all costs. Refer to section 6.3 for more details.

3 These requirements include the following:

- Section 60 of the Electricity Act 1996 (SA) requires that we take reasonable steps to ensure our infrastructure complies with the regulations, is safe and is safely operated;
- Clause 7 of SA Power Networks' Distribution Licence issued by the Essential Services Commission of South Australia, which requires us to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act and regulations.

Our recommendation is to invest $8.9M on the CBD Site Safety Program. This will remove numerous safety issues on the remaining high risk 33kV substations as part of the 33kV to 11kV conversion project. The continuation of the program will seek to ensure that those areas of the network are made safe for our CBD work personnel.

2.5 Protection Systems Compliance Program (AUG022; AUG035)

We have an established Backup Protection Program to rectify back-up protection systems in rural areas that are non-compliant with clauses S5.1.9(c) and S5.1.9(f) of the National Electricity Rules (NER). A continuation of this program in the 2025-30 RCP is proposed to meet our regulatory obligations / requirements under the NER.

Our existing Rural Backup Protection Program, which commenced in 2013, has rectified approximately 200 NER non-compliant feeders in rural areas. At the end of the 2020-25 RCP, a significant number of known network locations will still remain non-compliant, as follows:

- 101 Feeders in the 19kV network;
- All feeders included in the Bushfire Risk Management (**BFRM**) program have been excluded from this program expenditure.
- 19 Substations in the 11kV network; and
- 34 Substations in the regional 33kV and 66kV network.

We propose to upgrade existing or install new backup protection systems to rectify existing known non-compliances progressively over the next two RCPs. The extent of the works will be driven by a risk cost model, ensuring the lowest cost, technically compliant solution is developed.

This business case recommends investing $14.1m on the Protection Systems Compliance Program and continue the program for completion over the next two RCPs. This is an increased level of expenditure from historical spend, required to achieve compliance over two RCPs. The increased expenditure also reflects the increasing complexity required to resolve protection non-compliance on remaining known parts of the network.

- SA Power Networks' Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), which was approved by the Office of the Technical Regulator (OTR), with which we must comply under clause 8.1(c) of our Distribution Licence;
- various requirements relating to the maintenance of network assets referred to in the Electricity (General) Regulations 2012 (SA) (part of schedules 1 – 4 of those Regulations in particular);
- the Work Health and Safety Act 2012 (Section 19); and
- Chapter 5 of the NER (in particular, clauses 5.2.1 and 5.2.3) which require us to maintain and operate our facilities in accordance with: relevant laws and Australian standards, the requirements under the Rules, the power system and quality of supply standards set out in Schedule 5.1 of the NER, and good electricity industry practice.

3 Background

This business case justifies forecast expenditure for the 2025-30 RCP for SA Power Networks' safety related augex program, which comprises one input to our overall network augex.

3.1 The scope of this business case

The following programs of work are included within the safety related augex program:

- Substation Lighting Program;
- Substation Security and Fencing Program;
- Substation Infrastructure – Earth Systems Program;
- CBD Site Safety Program; and
- Protection Systems Compliance Program.

All backup protection system upgrades included in other proposed programs within our Regulatory Proposal have been excluded from the Protection Systems Compliance Program expenditure. This includes the following programs:

- Bushfire Risk Mitigation; and
- Planned Circuit Breaker (**CB**) replacements.

The following delineation has been made between capacity augex and expenditure within other streams:

3.1.1 Defining Safety vs Bushfire Risk and Resilience AUGEX

All work associated with the BFRM Program is included in the Bushfire Risk Management program of work in *Document 5.6.1 Bushfire Risk Management Business Case* and has been excluded from the network safety related augex within this business case.

3.1.2 Defining Safety vs REPEX

The planned asset replacement expenditure program within *Document 5.3.1 Network Asset Replacement Expenditure Business Case* takes into account any planned replacements as part of the network safety augex program of work so that these are not double counted.

3.1.3 Defining Safety vs Reliability AUGEX

All work associated with maintaining or improving the reliability of the network is included in the Reliability Augex program of work within *Document 5.9.3 Maintain Underlying Reliability Performance Business Case* and within *Document 5.9.5 Worst Served Customers Reliability Improvement Programs Business Case* has been excluded from the network safety related augex within this business case.

4 The identified need

The expenditure within this business case covers a number of distinct safety programs each with their own specific identified needs. The identified need specific to each program of work is set out in the later sections of this business case.

In assessing the identified needs, we considered the regulatory framework under the National Electricity Rules (**NER**) and the National Electricity Law (**NEL**) and, in particular how the capex is required to achieve the capex objectives and reasonably reflects the capex criteria, having regard to relevant capex factors. We also considered our relevant regulatory obligations / requirements in the NER, NEL and our jurisdictional instruments.

5 Approach to forecasting network safety expenditure

To forecast network safety related augex for the 2025-30 RCP, we use two methods to forecast the future expenditure required for each augmentation category: 'Historic' and 'Modelled':

- the **Historic** method is used when historical expenditure has proven to be steady, and where this is not expected to change materially in the future - this capex need has a recurrent nature, whereby the forecast remains consistent with historical levels and individual projects (investment needs) are identified and rectified in a short timeframe; and
- the **Modelled** method is used for augex projects that have drivers and needs which exhibit a degree of variability.

The method used for each expenditure program is detailed in Section 0.

Our detailed forecasting approach is outlined in Document 5.4.1 Augmentation Expenditure (Augex) Forecasting Approach and is summarised below:

Table 2: Expenditure forecasting methods

Title	ID	Description	Category (AER Forecast Model)	Augex investment trigger	Forecasting method
Substation Lighting	AUG019	Installation of (predominantly) indoor lighting to meet minimum safety standards	Safety	Safety – Substations	Historic
Substation Security & Fencing	AUG020	Upgrade of substation fences to high security to minimise break-ins and therefore public safety	Safety	Safety – Substations	Historic
Substation Infrastructure - Earth systems	AUG021	Upgrade and testing of substation earthing to meet minimum safety standards	Safety	Safety – Substations	Historic
Protection systems -compliance	AUG035, AUG022	Back up protection to at locations not compliant with the NER.	Safety	Safety – Protection Augmentation	Modelled
CBD Site Safety	AUG024	Work required to meet safety standards for workers	Safety	Safety – Substations	Historic & modelled

6 Expenditure programs

6.1 Substation Lighting Program (AUG019)

6.1.1 Proposal

We have an existing Substation Lighting Program in place to improve indoor emergency lighting at substations. A continuation of this program in the 2025-30 RCP is proposed.

6.1.2 Background

The Substation Lighting Program commenced in 2001 and was initiated following an incident that occurred at a CBD substation where a power failure of the local lights and power circuits resulted in workers being left in the vicinity of energised equipment with no visibility. The scope of this program was extended in the mid-2000s to include outdoor lighting after similar safety concerns raised by significant increases in copper theft and vandalism in substation switchyards.

We currently operate 349 dedicated substations and share ownership of another 451 substation sites with transmission network service provider ElectraNet. The Substation Lighting Program covers the upgrade and remediation of both indoor emergency exit lighting and exterior egress and yard floodlighting at our substations to meet regulatory obligations / requirements, including Australian and internal technical standards.

6.1.3 Our performance to date

A total of 238 sites are included in the Substation Lighting Program. A risk assessment of the sites is used to prioritise the delivery of the program. Since the commencement of the program, 160 sites have been rectified and 78 sites remain.

6.1.4 Drivers for change

A continuation of this program in the 2025-30 RCP is recommended. An increase in expenditure is not considered necessary to accelerate the completion of this program. The risk profile has remained consistent reflecting the pace of program delivery, and it is appropriate to use a top-down expenditure forecast approach, based on historic expenditure, for remediation of insufficient emergency lighting in substations that poses a safety risk.

6.1.5 Identified need

The identified need is to ensure that all of our substations have sufficient emergency egress lighting so that personnel working in our substations are able to safely exit the buildings in situations where primary lighting fails (i.e. the lighting is not intended to provide lighting to work under). Not all of our substations have sufficient emergency exit lighting and this poses a risk of physical harm to personnel. In seeking to address this identified need, our requirements are to prudently and efficiently: [4]

- maintain the safety of the distribution system (pursuant to the capex objective in clause 6.5.7(a)(4) of the NER) – in this case, to the maintain the safety with respect to personnel who work on substation assets within our distribution network;
- as required by clause 5.2.1(a) of the NER, align to good electricity industry practice, with particular reference to:

[4] As required by the capex criteria in clause 6.5.7(c) of the NER.

- Australian Standards on emergency lighting, AS 2293: Emergency escape lighting and exit signs
- SA Power Networks' Technical Standards, including: TS318 Substation Design – Emergency lighting; and TS 317 Substation Design – indoor and outdoor lighting; and

- comply with all regulatory obligations / requirements associated with the provision of standard control services (pursuant to the capex objective in clause 6.5.7(2) of the NER).

6.1.6 Options comparison

Options have not been considered within this business case given the specific nature of the need and lack of alternatives. This program is a continuation of the Substation Lighting Program included in the AER's Determination for the 2020-25 RCP.

6.1.6.1 Costs

The Substation Lighting Program expenditure for the 2025-30 RCP has been forecast based on historic expenditure which is approximately $0.07M per annum. Note, where lighting expenditure is undertaken in conjunction with other replacement projects such as switch room circuit breaker replacements, the lighting costs, being of such an immaterial amount, are included within these projects.

6.1.7 Recommendation

Our recommendation is to invest $0.4M on the Substation Lighting Program in the 2025-30 RCP – this investment is consistent with expenditure in the 2020-25 RCP.

6.2 Substation Security and Fencing Program (AUG020)

6.2.1 Proposal

We have an ongoing risk-based program of substation perimeter fence augmentation and video surveillance. A continuation of this program in the 2025-30 RCP is proposed.

6.2.2 Background

Historically, substation security typically consisted of a chainmesh fence topped with 2 or 3 rows of barbed wire, with an overall fence height of approximately 2.1m. The Substation Security and Fencing Program was initially focussed on bringing all substations to a basic level of security compliance. This involved raising the height of fences to 2.5m by installing barb wire and/or tiger loops to the top of the fence and addition of a bottom rail to prevent burrowing. These basic fence modifications achieved compliance with the minimum requirements of the Electricity (General) Regulations 2012.

With the completion of basic security improvements several years ago, the focus of the program shifted towards installation of high security fencing and surveillance systems.

Energy Networks Australia (**ENA**) published guidelines for electricity industry best practice for security of electricity networks.[5] These guidelines were initially published in 2006 and were primarily focussed on the physical security of substations and other electrical assets. They were updated in 2022 to include management of a broader range of security risk scenarios. The security guidelines recommend fencing constructed from weldmesh, expanded mesh, palisade or masonry with a minimum height of 2.9m

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5 Clause 5.2.1(a) of the NER requires SAPN to maintain and operate its facilities in accordance with (amongst other things) good electricity industry practice.

Weldmesh fencing is our preferred high security solution, except at sites with steep sloping terrain where palisade is more practical for construction.

Video surveillance is also a critical component of substation security. We use a range of surveillance systems, monitored either via in-house security personnel or external monitoring service.

6.2.3 Our performance to date

We assess the security risk for each substation in accordance with ENA guidelines. The assessments consider a range of factors including:

- general locality & evidence of criminal activity;
- proximity to other premises, schools, footpaths etc;
- proximity to public lighting;
- natural surveillance;
- live equipment risk (conductor height); and
- extent of existing security measures in place.

The output from these risk assessments assigns a risk score for each site and this score is used to prioritise installation of high security fencing and video surveillance. Of the sites already upgraded, 49 have palisade fencing and 53 weldmesh. There are currently 220 sites with low security chainmesh fencing. The remaining sites are either indoor or have other specific fence requirements.

A significant driver to upgrade chainmesh to high security fencing is the persistent threat of break-ins, usually for the purpose of stealing copper earthing cables. Chainmesh can easily be cut with basic hand tools (pliers), whereas cutting through a weldmesh requires considerable effort and power tools.

During the past five years there has been an average of one substation break-in per month. From these 60 incidents, only 4 involved high security fences and these 4 all targeted theft of specific construction equipment.

The historic expenditure of this program is approximately $2.2M per annum including fencing and video surveillance. This level of expenditure allows upgrade of fencing at 4 sites per year, which addresses the highest risk sites and is achievable from a construction and management perspective.

6.2.4 Drivers for change

Break-ins to zone substations continue to occur, largely motivated by copper theft. Risks of break-ins include safety of the intruder who may be exposed to dangerous high voltages. Invariably, once the security has been compromised there is free and uninhibited access to any inquisitive member of the public, including children. Furthermore, copper theft may disable our protection systems and expose the community to the risk of fatal electric shock.

There are 220 sites with low security chainmesh fencing that will require upgrade. These sites are prioritised for improvement based on the risk and frequency of break-ins in accordance with ENA guidelines and this has seen a focus on the metro areas. More recently, the type of theft from break-ins has changed with thieves targeting copper cable on transformer neutrals. This is a disturbing trend, with significantly increased risk of electrocution to the intruder, and lengthy outages required to facilitate repairs.

Since the 2020-25 RCP, there have been around 12 break-ins per year, however in 2021, we experienced 18 break-ins through substations with a basic level of security and 4 break-ins through high-security fences. Notably, the high security fence break-ins all occurred on substation construction sites where the thieves were targeting specific construction materials. Of the 18 basic level of security break-ins, 8 had transformer neutrals stolen, where the repair has involved de-energising around 5MVA of load for 12 hours (annual value of unserved energy of circa $2.1m).

We use a range of surveillance systems. The “Videofied” system is an intrusion detection and surveillance consisting of battery powered cameras that communicate wirelessly to a base station. When motion is detected, the base station sends a short videoclip via 4G network to the security monitoring company. There are approximately 80 of these systems installed in substations across the state. For critical sites, a high definition system is installed with hard wired cameras and continuous recording facilities.

6.2.5 Identified need

There is an ongoing need to progressively respond to the assessment that a number of our substation sites (circa 220) have insufficient security with respect to fencing and surveillance, and that this poses a safety risk of harm to the public such as serious injury, disability or death (through break-in or inadvertent entry) as well as a risk of theft of electrical assets. In seeking to respond to this identified need, our requirements are to prudently and efficiently:

- maintain the safety of the distribution system – in this case, to the risk of harm to members of the public (pursuant to the capex objective in clause 6.5.7(a)(4) of the NER;
- comply with all applicable regulatory obligations / requirements (pursuant to capex objective in clause 6.5.7(a)(2) of the NER – in this case, with respect to the Electricity Act (General) Regulations 2012 which place an obligation on us to prevent unauthorised access[6] and mandate that electrical substation owners and operators adopt and maintain reasonable site safety measures consistent with the service conditions and physical environment in which they operate[7];
- as required by clause 5.2.1(a) of the NER, comply with good electricity industry practice – in this case with the ENA guidelines on security of electricity networks, as updated in 2022 to include management of a broad range of security risk scenarios, and recommend fencing constructed from expanded mesh, palisade or masonry with a minimum height of 2.9m; and
- to take a progressive and risk based approach by which to improve the security of our substation assets to accord with what is currently good electricity industry practice[8].

6.2.6 Options comparison

Table 3 - Options Comparison - Substation Security and Fencing Program

Option 1: base case (business as usual)	Substation security base scenario for the substation security program maintains the same level of expenditure as the 2020-25 RCP (upgrade fencing at 4 sites per year – 55 years to completion). This is a risk-based approach to the program, where we target the highest risks first. At this level of expenditure, the full program will be complete in circa 70 years.	$12.9M
Option 2: new value	Increase level of expenditure for substation security. Accelerate the upgrade program to install high security fencing at 6 sites per year (40 years to completion).	$17.8M

6 Clause 6 of Schedule 3 to the Regulations.

7 As required by numerous clauses within the various schedules in the Regulations.

8 What amounts to good electricity industry practice naturally evolves and changes over time.

6.2.6.1 *Costs*

The Substation Security and Fencing Program expenditure for the 2025-30 RCP has been forecast based on the historic expenditure, which is circa $2.6M per annum including fencing and video surveillance.

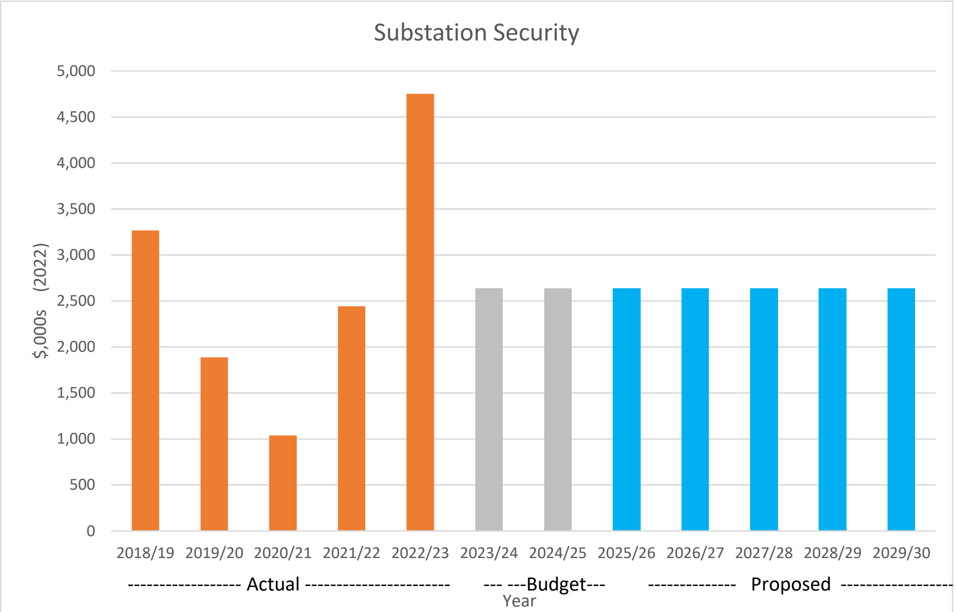

Figure 1: Historical vs Proposed Spend

6.2.7 Recommendation

Option 1 is proposed to maintain the existing level of expenditure for substation security. This allows substation security risk to be slowly reduced using historical events to target investment.

This business case recommends investing $12.9M on the Substation Security and Fencing Program in the 2025-30 RCP – this investment is consistent with expenditure in the 2020-25 RCP. This level of expenditure allows upgrade of fencing at 4 sites per year, which addresses the highest risk sites and is achievable from a construction and management perspective.

6.3 Substation Infrastructure – Earth Systems Program

6.3.1 Proposal

We have an ongoing earth grid remediation and test program. A continuation of this program in the 2025-30 RCP is proposed with a small increase to accommodate new cost sharing agreements with ElectraNet for management of earth grid testing of shared (co-located) substation sites.

6.3.2 Background

The Electricity (General) Regulations 2012 require earth grids to be: *"operated and maintained to safely manage abnormal electricity network conditions likely to significantly increase the risk of personal injury or significant property damage".*[9]

[9] Clause 52(1) of the Regulations.

Earthing systems are a critical safety infrastructure, and we have a legal and a corporate responsibility for their safe and effective operation, which is managed by ongoing earth grid test and remediation programs to address known issues and maintain performance of substation earthing systems.

6.3.3 Our performance to date

There are 400 substations in our distribution network, which includes 51 substation sites co-located with ElectraNet.

Our current earth grid testing and remediation strategy was implemented in 2009 and employs a risk management approach (developed in consultation with independent consultants) to assess and rank substations according to the safety risk imposed by earth grid condition. Our historical testing frequency under this strategy has been a delivery of 20 sites per year.

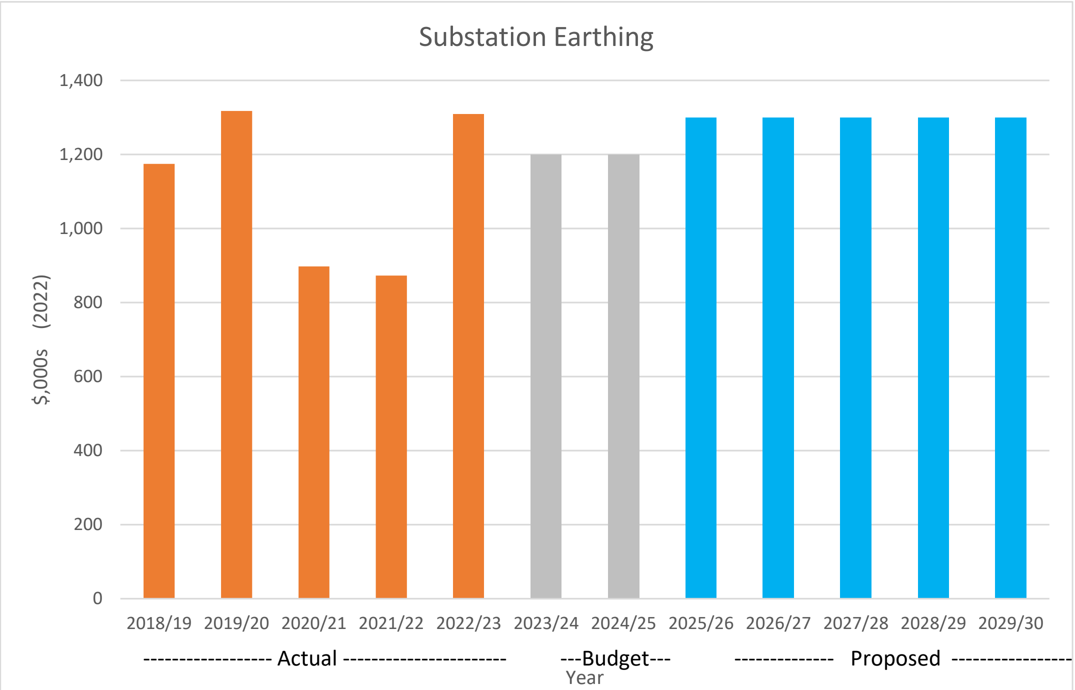

Figure 3: Historical vs Proposed Spend

6.3.4 Drivers for change

The current rate of testing and remediation of substation earth grids allows condition assessment of all (SA Power Networks') substation sites on a 15 year cycle. This aligns with good industry practice, published Australian standards & guidelines and our current understanding of asset degradation and risk.

In the current and previous RCPs, the management, delivery, and cost of earth grid testing and maintenance at shared (co-located) substation sites has been borne entirely by ElectraNet. Proposed future cost sharing arrangements with ElectraNet will require us to contribute towards ongoing delivery costs in future regulatory periods. The scope of this program includes 51 shared (co-located) substation sites, with testing performed by ElectraNet every ten years.

6.3.5 Identified need

There is an ongoing need for investment to ensure that our distribution network and system contains functioning and appropriate earthing systems. This is required to avoid safety harm to workers and the public, avoid risks of maloperation of network protection schemes under fault conditions, and to comply with regulatory obligations.

The dangers of Earth Potential Rise and associated step and touch potentials[10] are not only a risk within substation boundaries, and include nearby publicly accessible areas and adjacent telecommunication infrastructure. As critical safety infrastructure, it is essential that the adequacy and integrity of the earth grid is maintained. To ensure zone substation earth grids continue to meet safety performance requirements, they require ongoing condition monitoring, assessment and remediation works.

In responding to this identified need, our requirements are to prudently and efficiently:

- maintain the safety of the distribution system through the supply of Standard Control Services (**SCS**) (pursuant to the capex objective in clause 6.5.7(a)(4) of the NER) – in this case, to the risk of harm to people; and
- comply with all applicable regulatory requirements or obligations associated with the provision of SCS (pursuant to the capex objective in clause 6.5.7(a)(2) of the NER) – in this case the Electricity (General) Regulations 2012 which require earth grids to be *"operated and maintained to safely manage abnormal electricity network conditions likely to significantly increase the risk of personal injury or significant property damage".*[11]

6.3.6 Options comparison

Option 1: base case	Earthing base scenario maintains the current level of expenditure, testing all (SAPN only) sites on a 15-year cycle. New cost sharing arrangements with ElectraNet for testing shared (collocated) sites will require new SAPN contribution towards ElectraNet testing of approximately 5 sites per year; this equates to a small increase in funding over current historical expenditure in the 2020-25 RCP.	$6.3M
Option 2: investment	Increased level of expenditure for earthing remediation and testing to increase the testing frequency to a 10 year cycle (i.e. 30 sites tested per year). This option provides improved safety risk mitigation from increased monitoring and hazard remediation.	$9.5M

6.3.6.1 Costs

The Substation Infrastructure – Earthing Systems Program expenditure for the 2025-30 RCP has been forecast largely based on historic expenditure.

Additional funding is now required to contribute to shared management of earth testing at shared sites, where historically, ElectraNet had borne all costs. SA Power Networks' portion of shared costs is expected to be $100k per annum.

The historic expenditure of this program is around $1.1M per annum.

The unit cost per site for remediation and testing is in the order of $60k per site.

- **Option 1:**
    - Current 15-year cycle, 20 sites per year = $1.2m

10 Step and touch potentials refer to the flow of current under fault conditions across the body, causing injury. An appropriately designed earth grid will reduce these potentials to small levels, eliminating the risk of injury. Step potentials refer to the potential difference caused by the spacing between the feet of a person standing in the substation on a faulted structure. Touch potentials refer to the potential difference between someone touching a faulted structure and the feet of the person standing on the substation ground.

11 Clause 52(1) of the Regulations.

  - Additional cost for testing at ElectraNet sites $20k per site x 5 sites=$100k
  - Total: $6.5m[12] for 2025 – 2030
- **Option 2:**
  - Proposed 10-year cycle, 30 sites per year = $1.8m
  - Additional cost for testing at ElectraNet sites $20k per site x 5 sites=$100k
  - Total: $9.5m for 2025 – 2030

6.3.7 Recommendation

Option 1 is proposed to continue the existing level of expenditure for earth testing at 20 sites per year (15 year cycle), with a small increase to fund additional contribution costs of ElectraNet testing at shared sites.

This business case recommends investing $6.3M on the Substation Infrastructure – Earthing Systems Program in the 2025-30 RCP – this maintains the existing performance of the current 15 yearly test program and new cost sharing with ElectraNet for testing of shared sites. A continuation of this program will maintain current safety standards with respect to earth grid safety by addressing known issues and continuing to monitor the performance of substation earthing systems.

6.4 CBD Site Safety Program (AUG024)

6.4.1 Proposal

We have an ongoing CBD Site Safety Program to address a number of known safety risks identified at specific CBD substations. In the 2025-30 RCP, a continuation of this program is proposed to complete the risk mitigation of the remaining 33kV CBD Substations and thereby addressing all the associated high priority sites.

6.4.2 Background

Following safety concerns raised by our CBD workforce, we engaged a consultant in 2012 to undertake an external risk-based audit of our CBD sites, covering both 11kV and 33kV supplied sites. The site audits identified numerous safety issues at many CBD substations, with the key safety issues being:

- challenging access and egress;
- exposed live parts;
- sites in basements with access only by older-style ladders (slippery and narrow) with no fall arrest; and
- confined spaces at some sites such that if a person fell, they could make contact with live bushings.

We have also identified key hazards at these sites beyond the scope of this audit:

- LV switchboards with insufficient fault rating or arc flash venting;
- Switchgear unable to be operated live due to failure risk; and
- 33kV bifurcating joints in cable vaults and manholes, which are considered to be high risk.

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[12] Forecast totals may vary slightly due to $ term conversions.

Sites were categorised based on the inherent site risk level[13] and a list of high priority sites[14] for remediation was generated which then allowed us to determine the most efficient and prudent action. Further scoping identified that migrating 33kV substations into the 11kV network was the preferred solution[15] that eliminated numerous safety issues as it allowed us to abandon those sites which were deemed high priority for remediation.

Our CBD Strategic Plan outlines the optimal sequencing of the 33kV to 11kV conversion program based on complexities around constructability, delivery, and site dependencies in addition to safety risk level. With the ultimate goal being to remediate the high priority sites as soon as practicable, we developed a coordinated and systematic site remediation order for delivery of the program across three RCPs.

6.4.3 Our performance to date

Since the commencement of the program in 2015, twelve sites are expected to be migrated to 11kV by 2025 with five remaining sites planned for the 2025-30 RCP. Table 4 outlines the number of 33kV sites completed or planned for remediation, and the corresponding quantity of high and medium risk sites being remediated.

Table 4: Program performance and expected delivery

RCP	33kV Sites	High Risk Sites	Medium Risk Sites
2015-20	5	2	2
2020-25	7	1	4
2025-30 Target	5	3	1

6.4.4 Drivers for change

The cost of remediating CBD 33kV sites are highly variable due to site specific requirements, and not correlated to the capacity of the site.

The proposed continuation of the program aims to complete the remainder of 33kV sites identified in the program which will see four 33kV sites planned for conversion to 11kV and one 33kV upgrade project planned for completion in the 2025-30 RCP. Relative to the 2015-20 and 2020-25 RCP, the sites identified for conversion over the 2025-30 RCP have a greater level of complexity and significant safety issues (including three high priority sites). As a consequence, a higher average capital costs per site is reasonable to expect whilst still delivering a consistent number of sites with previous RCPs.

6.4.5 Identified need

The primary objective of this program is to mitigate safety risk, whilst also remaining compliant with applicable regulatory obligations / requirements relating to our operations, and our distribution licence[16]. The risks identified on the audited sites pose an unacceptable level of risk to our workers. The CBD Site Safety Program addresses safety and compliance risks due to inadequate electrical clearances, poor access within the substation, absence of emergency exits, inadequate ventilation and other site-specific hazards.

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13 *Site Risk Level* (High/Medium/Low/Negligible) is based on the severity of the identified hazard(s) for each site and quantified using SA Power Networks' Risk Matrix and based on the likelihood and consequence associated with the safety risk.

14 *High Priority Sites* list was generated as part of the audit and selection was based on the urgency to address key hazards identified including proximity and exposure to live electrical equipment, difficulty of escape route and condition of physical environment.

15 The solution is also commonly referred to as "33kV to 11kV Conversion" as the customers supplied from these 33kV substations are transferred to the 11kV network allowing us to decommission the assets with safety issues at the 33kV substation.

16 Clause 7 of SA Power Networks' Distribution Licence issued by Essential Services Commission of South Australia (**ESCoSA**), requires us to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act and regulations.

33kV substations in the CBD are typically located in tight spaces and/or building basements. There are some that are indoor, sub-basement and many are installed within high-rise commercial and office areas of the Adelaide CBD, typically located within consumer's premises. These sites are typically inadequate to house modern 33kV transformers and switchgear. The larger size of 33kV assets compared to 11kV assets means that clearance requirements often cannot be achieved using modern 33kV assets. By converting these sites to 11kV, the safety risks for personnel on site will be addressed. In cases where the site hazards can be addressed by using modern 33kV assets, consideration will be given to retaining the site on the 33kV network provided this is a cost-efficient solution.

A secondary benefit of the program is reduced risk associated with the following:

- removal of 33kV bifurcation joints, which limit switching configurations;
- increased operability of the CBD 33kV network due to removal switchgear with safety and operational restrictions; and
- minimising planned and unplanned outage risks within the CBD area.

As a result of these considerations, the identified need is to comply with all applicable regulatory obligations / requirements, standards[17] and safety requirements applicable to our CBD sites in addressing the safety risks identified including:

- Section 60 of the *Electricity Act 1996 (SA)*, which requires us to take reasonable steps to ensure our infrastructure complies with the regulations, is safe and is safely operated.
- Clause 7 of our Distribution Licence issued by ESCoSA which requires us to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act and regulations;
- SA Power Networks' Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**), which was approved by the Office of the Technical Regulator (**OTR**) which we are required to comply with under clause 8.1(c) of our distribution licence;
- the various requirements relating to the maintenance of network assets referred to in the Electricity (General) Regulations 2012 (SA) (and section 12 of schedules 1 – 4 in particular);
- the various requirements referred to in the Work Health and Safety Act 2012 (Section 19); and
- Chapter 5 of the NER (in particular, clauses 5.2.1 and 5.2.3), which require us to maintain and operate our facilities in accordance with: relevant laws and Australian standards, the requirements under the NER, the power system and quality of supply standards set out in Schedule 5.1 of the Rules, and good electricity industry practice.

[17] Relevant standards include:

- AS 1657 Fixed platforms, walkways, stairways and ladders - Design, construction and installation
- AS 1668.2 The use of ventilation and air conditioning in buildings
- AS 1851 Routine Service of Fire Protection Systems and Equipment
- AS 2444 Portable Fire Extinguishers and Fire Blankets - Selection and Location Requirements
- AS 2865 Confined Space
- AS 3000 Wiring Rules
- AS/NZS 1680.2.4 Interior and Workplace Lighting - Industrial tasks and processes
- AS/NZS 1715 Selection, use and maintenance of respiratory protective equipment
- AS/NZS 1716 Respiratory Protective Devices
- AS/NZS 1841 Portable Fire Extinguishers

6.4.6 Options comparison

Options were not considered within this business case given its specific need and lack of alternatives. This program is a continuation of the safety program included in the AER's capex allowance in its 2020-25 Determination. Deferring this program is not appropriate as it does not reasonably address the known safety issues at the high risk 33kV substations.

6.4.6.1 Costs

The CBD Site Safety program employed both a top-down and simplified bottom-up methodology to prepare the forecast expenditure, due to the site-specific requirements resulting in highly variable site costs, making it insufficient to use a purely top-down approach based on historic expenditure. The program costs were further refined based on the actual costs of remediated sites, incorporating the lessons learned, and our understanding of the differences between the relevant sites and the safety hazards identified.

Given the remaining sites proposed for the 2025-30 RCP have a greater level of complexity compared to the previous sites, it is reasonable to assume a higher average capital costs per site. Considering the most costly remediated site to date is $2.4m (Da Costa Substation), we propose an average capital costs of $1.8M per site for the 2025-30 RCP would be appropriate. Based on this, the remaining five 33kV sites can be delivered within the 2025-30 RCP at a total cost of $8.9M.

6.4.7 Recommendation

This business case recommends investing $8.9M on the CBD Site Safety Program in the 2025-30 RCP. This will address the remaining high risk safety issues that were identified for remediation within CBD 33kV substations. A continuation of this program will ensure all CBD 33kV substations are safe locations, in respect to standards and obligations, and can continue to be operated safely.

6.5 Protection Systems Compliance Program

6.5.1 Proposal

The NER require us to provide sufficient primary and backup protection systems to ensure that a fault of any fault type anywhere on our distribution system is automatically disconnected within the fault clearance time required under Clause S5.1.9(f). We have identified areas of the network where back up protection does not comply with clauses S5.1.9(c) and S5.1.9(f) of the NER and at the end of the current RCP 154 back up protection systems will remain non-compliant.

The Protection Systems Compliance Program encompasses all identified non-compliant protection systems across the network and seeks to bring us into compliance with the NER requirements. An increase in expenditure is required compared to our historic expenditure for our existing Rural Backup Protection Program to address additional sites not previously covered by the program.

Options are presented for program delivery in five or ten years with details outlined in the following sections. This business case recommends investing $14.1M on the Protection Systems Compliance Program and continue the program for completion over the next two RCPs.

6.5.2 Background

Clause 5.2.3(b) of the NER states that a Network Service Provider must comply with the power system performance and quality of supply standards described in schedule 5.1. Clause S5.1.9 of Schedule 5.1 of the NER sets out the protection system and fault clearance time requirements for distribution systems. In particular, clause S5.1.9(c) provides that:

> "Subject to clauses S5.1.9(k) and S5.1.9(l), a *Network Service Provider* must provide sufficient primary *protection systems* and backup *protection systems* (including *breaker fail protection systems*) to ensure that a fault of any *fault type* anywhere on its *transmission system* or *distribution system* is automatically *disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f)."*

It follows that, SA Power Networks is (relevantly) **required** under clauses S5.1.9(c) and S5.1.9(f) to provide such backup protection systems as are reasonably required to ensure that a fault of any fault type anywhere on SA Power Networks' distribution system is automatically disconnected within the fault clearance time required under clause S5.1.9(f). Clause S5.1.9(f) provides as follows

> "The fault clearance time of each breaker fail protection system or similar back-up protection system of a Network Service Provider must be such that a short circuit fault of any fault type that is cleared in that time would not damage any part of the power system (other than the faulted element) while the fault current is flowing or being interrupted."

Backup protection systems are implemented by a Network Service Provider to supplement primary protection systems. Backup protection systems function by operating when primary protection systems do not clear a power system fault or primary protection systems fail to operate as intended. Figure below represents a typical primary and backup arrangement on a feeder with B being the primary protection device and A being the backup protection system for the fault location represented.

What is backup protection?

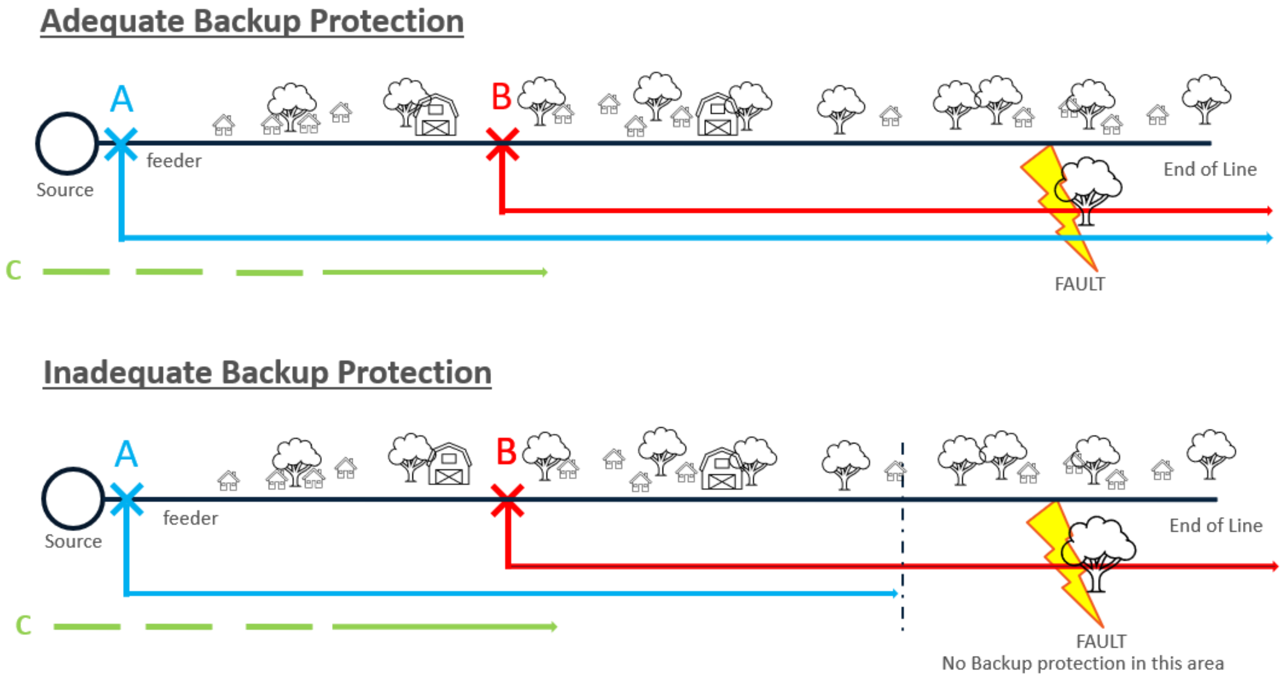

Figure 4: Adequate vs Inadequate Backup Protection

Under the Protection Compliance Program, backup protection is applied as a "primary and backup" arrangement where the backup scheme is designed to have a slower operating time and/or inferior selectivity[18] to the primary protection such that it only operates in the case of a failure of the primary protection scheme.

We have progressively identified several non-compliant backup protection systems located throughout the network, where it has been determined that, in the event of a failure of primary protection, the existing backup protection systems **do not** clear power system faults as per the requirements of clause S5.1.9(f). If a fault was to occur at these identified locations, under these circumstances, the existing protection arrangement would allow the network to continue to feed the faulted section without interruption until such time that subsequent network damage occurs in a location remote to the original fault. This sequence of events is non-compliant with clause S5.1.9(f), in the event of a primary protection systems failure. Failure to clear power system faults will result in subsequent damage to non-faulted parts of the network and interruption to supply.

The types of non-compliant backup protection systems identified in these reviews are categorised into the following different configurations:

- 66kV and 33kV fuses installed on the high side of substation transformers at regional substations;
- 11kV mechanical relays installed on the bus bars or transformers; and
- 19kV feeder protection[19].

The identified non-compliant backup protection systems are not definitive and further non-compliant backup protection systems may be identified through business as usual protection review activities.

18 Inferior selectivity refers to when more assets will be removed from service to clear the fault than would otherwise be the case.

19 19kV Feeder Protection refers to Liquid Fuses installed before the 19kV isolation transformer.

Identified non-compliant back up protection systems have been assessed based on the following criteria:

- Where a back up protection system **does not detect and operate** for any fault on the network beyond the primary protection system.
  - Failure to isolate any fault will result in damage to another asset on the network. This is non-compliant with clause S5.1.9(f) in the NER.
- A back up protection system **does not detect and operate** before the damage characteristic of any asset on the network other than the faulted asset.

6.5.3 Our performance to date

Our existing Rural Backup Protection Program was established in 2013 to mitigate and maintain the network risks associated with inadequate backup protection in rural areas. We have rectified approximately 200 low complexity and cost sites since the commencement of the program.

The Protection Systems Compliance Program expands on this existing program to include all non-compliant sites, which are of higher complexity and cost.

We have identified areas of the network where back up protection does not comply with clauses S5.1.9(c) and S5.1.9(f) of the NER and at the end of the current RCP 154 back up protection systems will remain non-compliant as follows:

- 101 Feeders in the 19kV network
  - All feeders included in the BFRM program have been excluded from this program expenditure. The back up protection on these feeders will be fixed as part of BFRM program of works.
- 19 Substations in the 11kV network
- 34 Substations in the regional 33kV and 66kV network

The non-compliant back-up protection systems situated in the 11kV, 33kV and 66kV parts of the network are of high complexity and cost. Additional funding will be required to continue to meet compliance in a timely manner.

6.5.4 Drivers for change

We will address non-compliant back up protection systems at sites where planned work is undertaken as part of other programs. These sites have been excluded from this business case and only identified non-compliant back up protection systems located at sites where there is no foreseeable planned work are included in this business case. All non-compliant backup protection systems need to be rectified in a timely manner to reduce any associated risk with non-compliance.

The increased level of expenditure, from historical spend, reflects the increasing complexity required to resolve protection non-compliance on remaining known parts of the network. Relatively inexpensive remediation options historically used are no longer considered fit for purpose as they pose other operational and reliability risks.

6.5.5 Identified need

There is a need for investment in response to our assessment that a number of locations on our distribution network, particularly in rural areas, have none or have insufficient backup protection. This has been determined via a protection system assessment comparing the damage curves of network assets beyond backup protection systems.

Functioning backup protection is a regulatory obligation / requirement, and failure to have backup protection, or insufficiency in backup protection, poses a risk of damage to other parts of the network (in addition to where a fault occurs), a safety risk to the public of electrocution, and safety risk to the community via the potential to start a bushfire such as through electric arc ignition. In responding to this identified need, our requirements are to prudently and efficiently:

- comply with all applicable regulatory obligations or requirements associated with the provision of SCS (pursuant to the capex objective in clause 6.5.7(a)(2) of the NER), in this case with respect to:
  - section S5.1.9(c), which requires that we must provide sufficient primary protection systems and backup protection systems to ensure that a fault of any fault type anywhere on the distribution system is automatically disconnected;
  - section S5.1.9(f), which requires that the fault clearance time of each breaker fail protection system or similar backup protection system must be such that a short circuit fault of any fault type that is cleared in that time would not damage any part of the power system (other than the faulted element) where the fault current is flowing or being interrupted; and
- maintain the safety of the distribution system through the supply of SCS (pursuant to the capex objective in clause 6.5.7(a)(4) of the NER)

6.5.5.1 *Regional 33kV and 66kV Network*

The fuses that are installed on 66kV and 33kV high side substation transformers at smaller regional substations are unable to provide backup protection to the 11kV feeders emanating from these substations. If the primary protection systems on these feeders were to fail to operate, the fuses would only operate once the transformer(s) has become damaged due to the uncleared fault on the 11kV network. This creates a situation that is not compliant with the NER requirements. The typical configuration of Regional 33kV and 66kV Network is shown in Figure .

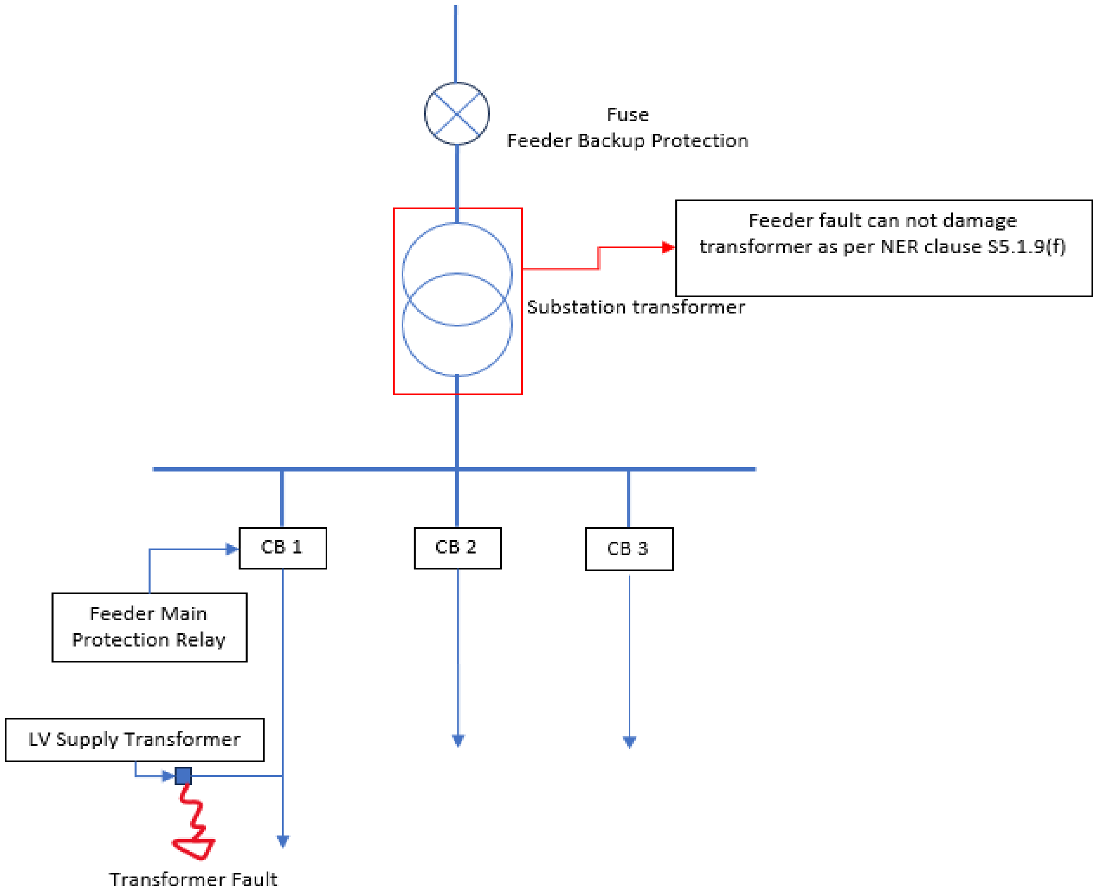

Figure 5: Typical Regional 33kV and 66kV Network

The characteristics of the 66kV and 33kV fuses at regional substations have been compared against the minimum fault current and damage characteristic of the substation transformer to identify locations with non-compliant protection systems.

6.5.5.2 11kV Network

The existing 11kV electromechanical relays installed on a number of 11kV bus bars or transformers are not capable of providing backup protection for the 11kV feeder primary protection systems. Electromechanical relays installed on the bus bar or transformer are unable to detect and isolate for all faults on 11kV feeders. If the feeder primary protection fails or does not operate as intended then, the electromechanical relays installed on the bus or transformer will not detect and isolate until further subsequent damage has occurred, such as damage to conductor along the feeder. The typical configuration of 11kV electromechanical relays is shown in Figure 2.

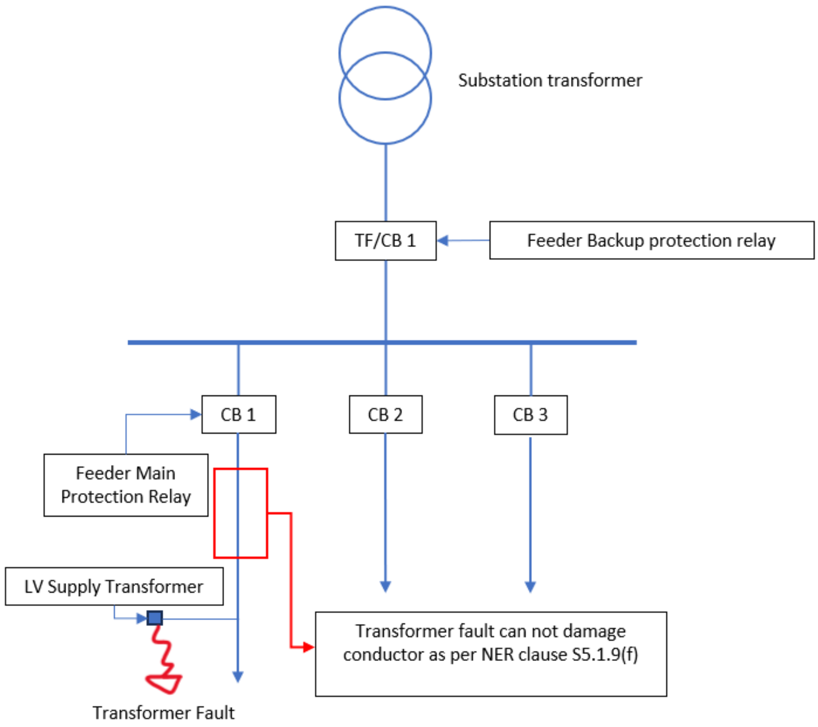

Figure 2: Typical 11kV Network

6.5.5.3 19kV Network

The non-compliant 19kV backup protection systems identified for the 19kV feeders comprises of a 33kV Liquid Fuse installed before the 19kV isolation transformer. To comply with clause S5.1.9(f) of the NER, the Liquid Fuse is required to isolate feeder faults before damage occurs to the 19kV Transformer, refer to Figure below.

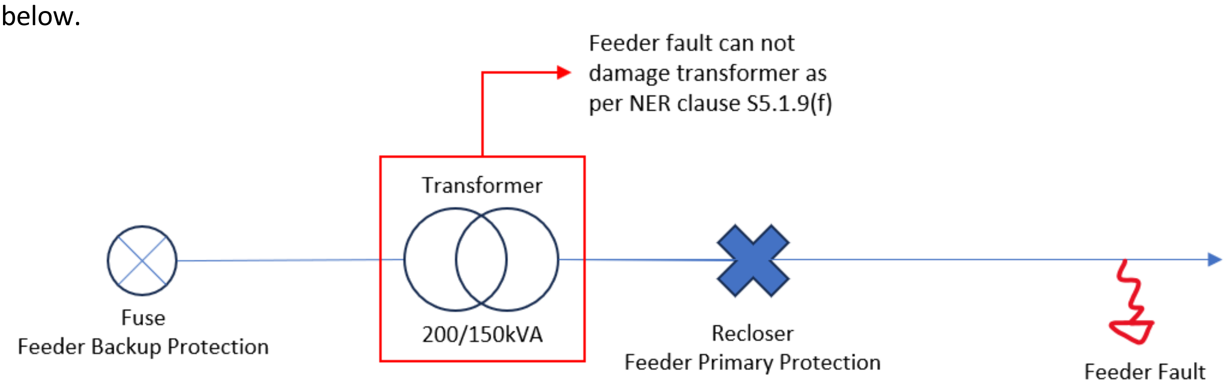

Figure 7: Typical 19kV Network Configuration

6.5.5.4 Other risks

In addition to being non-compliant with our obligations, there are several risks associated with these inadequate backup protection schemes including:

1. Public/Worker Safety;
2. Customer Reliability;
    a. Prolonged outages – due lack of switching capability;
    b. Temporary bypass solutions;
3. Damage to assets.

These associated risks have been used to create a risk cost model which have been categorised as safety, bushfire and transformer damage risks, as follows:

- Safety risk - the risk of public electrocution when in contact with the energised faulty network asset that otherwise could have been de-energised had backup protection been provided.
- Bushfire risk - the risk of electric arc ignition that could result in a fire start event and ultimately lead to a bushfire.
- Transformer damage risk - the risk of permanent transformer damage due to an uninterrupted fault and the subsequent prolonged outage.

Each risk is calculated based on the likelihood of the event occurring and the consequence of the event occurring. The risk and likelihood is based on historical incident and outage data over a 14 year period.

6.5.6 Options comparison

We propose to augment protection systems to rectify existing known non-compliances over the 2025-2030 RCP and future RCPs. The lowest cost, technically compliant solutions will be adopted. A risk cost model will be used to prioritise the deployment.

Table 5 - Options comparison - Augment protection systems

Option 1: base case (10 years to fix non-compliant sites)	Investment is required to upgrade protection systems to be compliant with the NER and reduce the risk of a non-compliant backup protection system contributing to the start of a bushfire. To comply with the NER, it is necessary to upgrade the following sites in the 2025-30 RCP: ▪ 101 Feeders in the 19kV network ▪ 16 Substations in the 11kV network ▪ 21 Substations in the regional 33kV and 66kV network The non-compliant backup protection systems in the 19kV network will be rectified by installing 19kV backup fuses. This is SA Power Networks current practice. The non-compliant backup protection systems in the 11kV network will be rectified by upgrading the existing electromechanical bus protection devices with new digital devices to provide backup protection to 11kV Feeders.	$14.1M

	The non-compliant backup protection systems for the substations in the 33kV network will be rectified by installing new 33kV reclosers with new protection relays at substations where the transformer rating is greater than 1MVA. At substations with a transformer rating less than 1MVA a backup fuse solution will be deployed. The non-compliant backup protection systems for the substations in the 66kV network will be rectified by installing new 66kV circuit breakers and new protection relays. The number of sites remaining to be upgraded beyond the 2025-30 RCP include: ▪ 3 Substations in the 11kV network ▪ 13 Substations in the regional 33kV and 66kV network	
Option 2: base Case (5 years to fix non-compliant sites)	This Option is the same technical approach as in Option 1 however proposes that all non-compliant sites are addressed in the 2025-30 RCP rather than over a 10-year period.	$23.35M
Option 3: investment (10 years to fix non-compliant sites)	Option 2 employs the same technical approach as option 1 where non-compliant backup protection systems are addressed in accordance with the NER and additional reliability, Supervisory Control and Data Acquisition (**SCADA**) and safety benefits are gained. However, under this option 3, a different technical approach will be deployed for each of the non-compliant network areas. Alternate solutions for addressing the non-compliance have been recommended which present additional benefits. The non-compliant backup protection systems in the 19kV network will be rectified by installing 19kV backup reclosers. The non-compliant backup protection systems for the substations in the 11kV network will be rectified by installing new midline reclosers on each 11kV feeder. There are no viable alternative solutions to meet NER backup protection system requirements for the 33kV network. The non-compliant backup protection systems for the substations in the 66kV network will be rectified by installing a new high speed telecommunication network and new protection relays, to operate remote circuit breakers.	$20.05M
Option 4: investment (5 years to fix non-compliant sites)	This Option is the same as Option 3 however proposes that all non-compliant sites are addressed in the 2025-30 RCP rather than over a 10-year period.	34.8M

In Option 1 and 3 we plan to rectify our non-compliant back up protection systems over the next two RCPs to achieve compliance with the NER. The following sites will be targeted in the 2025-30 RCP:

- 101 Feeders in the 19kV network
- 16 Substations in the 11kV network
- 21 Substations in the regional 33kV and 66kV network

The remaining non-compliant sites are of higher complexity and are proposed to be addressed in the 2030-35 RCP:

- 3 Substations in the 11kV network
- 13 Substations in the regional 33kV and 66kV network

In Option 2 and 4 we propose to complete all works within the 2025-30 RCP.

For the purposes of further analysis below Option 1 and 2 will be referred to as Scenario 1 and Option 3 and 4 shall be referred to as Scenario 2.

The recommendation for each category is summarised below:

6.5.6.1 Feeders in the 19kV network

Option 1 and Option 2 (Scenario 1)

Install 19kV backup fuses on 19kV feeders providing the necessary backup protection to ensure that 19kV transformers and conductors are protected in the event of a primary protection failure.

Option 3 and Option 4 (Scenario 2)

Install 19kV backup reclosers on 19kV feeders providing the necessary backup protection to ensure that 19kV transformers and conductors are protected in the event of a primary protection failure. Modern reclosers are intelligent devices which are capable of SCADA and telecommunication systems. The 19kV network is typically in rural areas of South Australia which are often hard to access or are in bushfire areas. New SCADA communications allow for operators to control recloser devices remotely, allowing switching to occur without attending site, reducing risks to operators. New reclosers can enable the latest safety features remotely to provide high-speed protection during heightened bushfire risk.

Recommendation

The 19kV network supplies customers in low density customer areas which historically have not justified the expenditure of modern reclosers. Scenario 1 is the preferred option as the extra benefits of Scenario 2 do not justify the economic cost.

6.5.6.2 Substations in the 11kV network

Option 1 and Option 2 (Scenario 1)

Upgrade the existing electromechanical devices with new digital devices at the substation. These new relays will be able to implement sophisticated control schemes and can implement the latest safety schemes deployed on SA Power Networks 11kV Network.

Option 3 and Option 4 (Scenario 2)

Install new midline reclosers on each 11kV feeder. Midline reclosers are installed on the 11kV network to meet reliability and protection requirements. They have historically been installed on long 11kV feeders and been proven to improve reliability by reducing the number of customers effected by outages and duration of outages. They also are regularly used in our automation program which has been implemented to minimise the impacts to customers on a faulted feeder. An additional benefit of installing new reclosers is the improved sensitivity in fault detection at the end of feeders, reducing the safety risks.

Recommendation

Scenario 1 to install new digital devices and replacing the existing electromechanical devices at 11kV substations is the preferred option as installing new midline reclosers on each feeder is significantly more expensive with the benefits not outweighing the additional cost.

6.5.6.3 Substations in the Regional 33kV network

Option 1 and Option 2 (Scenario 1)

Install new 33kV reclosers with new protection relays at substations where the transformer rating is greater than 1MVA and backup fuses where the transformer rating is less than 1MVA.

Modern 33kV substation design implements a protection system with 33kV reclosers and 11kV neutral over current protection. It provides additional benefits such a SCADA monitoring and improved safety for SA Power Networks operators.

Based on analysis it is not feasible to install 33kV reclosers for transformers with a rating of 1MVA as the historical expenditure for a new recloser is more than the cost for a transformer of that size.

Option 3 and Option 4 (Scenario 2)

Same as Option 1 and Option 2. There are no viable alternative solutions to meet NER backup protection system requirements for the 33kV network.

Recommendation

Installing 33kV reclosers at substations where the transformer rating is greater than 1MVA and backup fuses where the transformer rating is less than 1MVA is recommended. This is in line with modern 33kV substation design. This is the same solution for all Options.

6.5.6.4 Substations in the Regional 66kV network

Option 1 and Option 2 (Scenario 1)

Install new 66kV circuit breakers and new protection relays at substations.

Modern 66kV substation design implements a protection system with 66kV circuit breakers and 11kV neutral over current protection. It will provide additional benefits such a SCADA monitoring and improved safety for SA Power Networks operators.

Option 3 and Option 4 (Scenario 2)

Install a new high speed telecommunication network and new protection relays, to operate remote substation's circuit breakers. This solution increases the complexity of the communication network but reduces the number of physical 66kV circuit breakers required to be installed, reducing the cost of maintenance on the network. The implementation of this solution will enable SA Power Networks to achieve compliance with the NER, however, it will affect the reliability to customers as remote substations on the 66kV network are not radial and often supply multiple substations.

Recommendation

Scenario 1 to install new 66kV circuit breakers and new protection relays at substations is the preferred solution. This is in line with modern 66kV substation design.

6.5.6.5 Costs

The Protection Systems Compliance Program expenditure for the 2025-2030 RCP has been forecast based on a modelled approach using the number of sites requiring an upgrade to the protection system multiplied by the historic unit rate of the upgrade. All sites identified to have insufficient backup protection systems are required to be remediated to comply with the NER. The program of work for the 2025-2030 RCP will be prioritised on site remediation costs, resourcing requirements and site-specific complexities, in addition to the consideration of risk cost, to achieve compliance in the nominated delivery period.

6.5.6.6 NPV Analysis

The benefits as identified and calculated from the risk cost model[20] are small compared to the program delivery cost (under all options). Thus, the Net Present Value (**NPV**) benefits are negative and are used to determine the least cost technically compliant solution to achieve compliance.

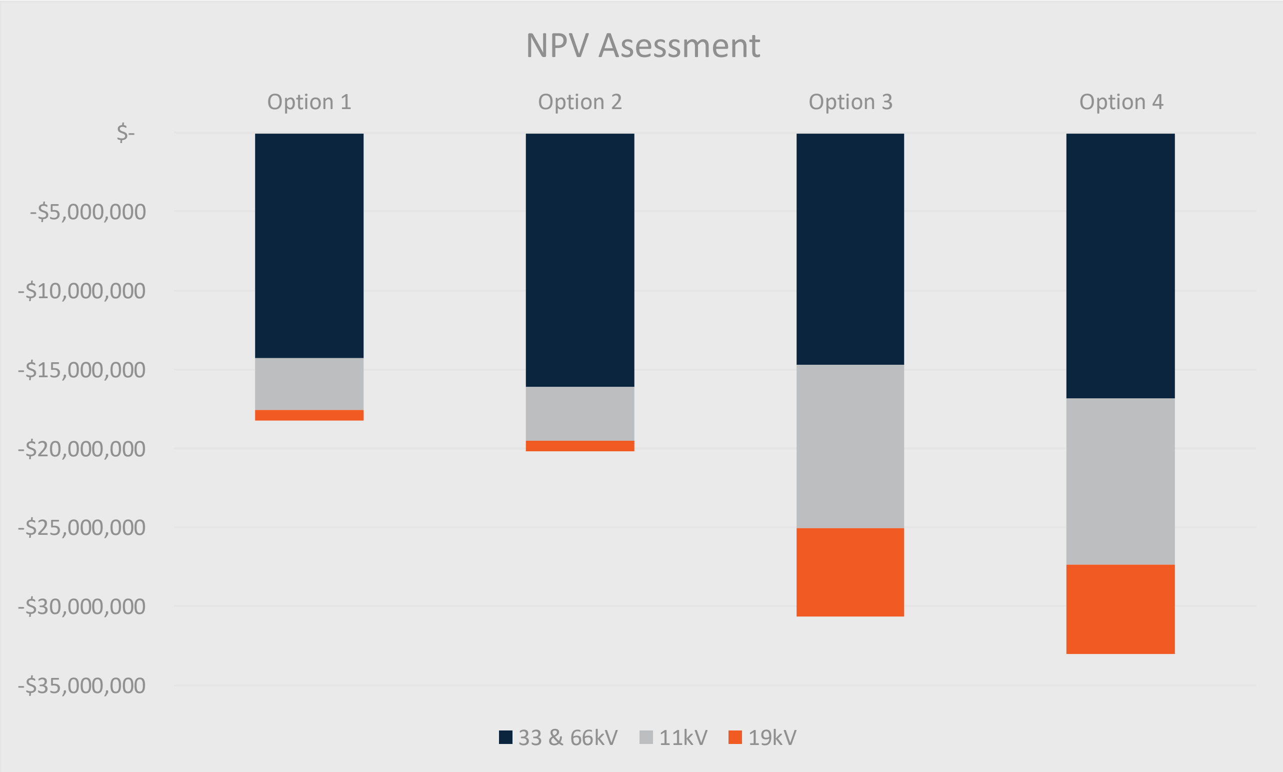

Figure 8: NPV Assessment[21]

Scenario 1 (being options 1 or 2) is significantly more economic than scenario 2 (options 3 or 4). The risk costs associated with each non-compliance are small when compared to each of the proposed solutions for each of the non-compliant back up protection systems categories. The assessment shows that the additional reliability, SCADA and safety benefits proposed under Scenario 2 are not justified.

Achieving compliance over two (2) regulatory periods does not materially increase the risk provided the work identified for inclusion in the 2025-30 RCP is completed as recommended in Option 1. Furthermore, the longer delivery timeframe presents economic benefits. An accelerated program to achieve compliance by the end of 2030 will see the remediation of the 33kV and 66kV non-compliant site being subject to elevated resource costs to achieve the accelerated program delivery.

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[20] Refer to Appendix A for further details on how risk cost has been quantified using SA Power Networks Risk Matrix.

[21] The benefits (albeit expected to be small) have not yet been fully calculated and therefore have not been inserted into this figure.

6.5.7 Recommendation

Our recommendation is to invest $14.1M to deliver the Protection Systems Compliance Program in the 2025-30 RCP, this is an increase in level of expenditure from historic which reflects the increasing complexity required to resolve protection non-compliance on remaining known parts of the network.

Whilst completing all work within a 5-year period is preferable, we recognise the increased cost associated with achieving delivery, due to the associated resource cost, is not as cost-effective as option 1. This program will address non-compliance with clauses S5.1.9(c) and S5.1.9(f) of the NER with forecast remediation by the end of 2035, as part of risk based progressive approach by which to move toward compliance.

7 Alignment to consumer and stakeholder engagement

The identified needs of this business case were not specifically deliberated on as part of our consumer and stakeholder engagement process, on the basis that they were not considered, together with our Consumer Advisory Board (CAB) to be priority topics for engagement.

However, throughout our engagement program, our customers were consistently concerned with the need for us to comply with regulatory obligations and to maintain levels of safety to our employees and the public.

Further, the costs of this program were included in the total expenditure figures that were presented to consumers throughout each stage of our engagement program, so that customers understood the totality of the service and price outcomes that they were deliberating on.

Subsequent to our People's Panel process, we also published a Draft Proposal to play back how we have given effect to customer recommendations and to confirm that those recommendations remain valid given continued cost of living pressures and to obtain further input to refine our Regulatory Proposal. Submissions received on our Draft Proposal did not specifically comment on the investment needs addressed via this business case. However, SACOSS outlined their support for us seeking expenditure to maintain current core reliability and service levels and to meet our obligations.[22]

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[22] SACOSS, *South Australian Council of Social Service Submission on SA Power Networks' 2025-30 Draft Regulatory Proposal*, September 2023.

8 Deliverability

We have developed a plan to ensure that we can deliver the recommended project in this business case together among all of the increased volume of work reflected in the programs that comprise our total network expenditure forecast in our Regulatory Proposal. This plan considers the detailed implications of our proposed overall uplift in total network expenditure for our required workforce and supporting internal services of information technology, feet, property and human resources.

We consider that our plan is realistic and achievable over the 2025-30 RCP. The details of our approach are set out in our accompanying document, '5.2.5: Resourcing Plan for Delivering the Network Program'.

A. Appendix A – cost models

8.1 Cost Models

The risk cost model calculations have been performed using the assumptions described below. For detailed calculations refer to SA Power Networks "NPV Calculation.xlsm"

8.2 Assumptions

The following assumptions have been made in determining the NPV:

- **Discount Rate:**
  - A Central Discount Rate of 3.73% has been used.
- **Likelihood of Non-operation:**
  - Recloser non-operation is derived based on historic records of reclosers failing to open between 2013 and 2023:
    - Number of reclosers that failed to open:
      - 13 in the 11kV Network
      - 32 in the 19kV Network
    - Total number of reclosers installed on the Network:
      - 646 in the 11kV Network
      - 536 in the 19kV Network
    - Recloser fail to open rate:
      - 0.0019 per year for the 11kV Network
      - 0.0074 per year for the 19kV Network
  - 11kV Primary Protection non-operation is derived from the following calculation:
    - Number of circuit breakers that fail to open when a protection device has issued an open command: 0.75/year
    - Number of protection devices that fail under fault conditions: 0.72/year
    - Total number of primary protection assets installed on the Network: 1210
    - Primary Protection non-operation: 0.0012 per year
- **Risk Cost:**
  - Safety Risk Cost has been calculated based on the following:
    - Percent of non-compliant back up protection system
    - Likelihood of primary protection non-operation: as per above.
    - Likelihood of a death or injury resulting from a fault:
      - Death likelihood 1 in 200 years
      - Injury likelihood 1 in 50 years
    - Cost of a Death or Injury as per corporate risk:
      - Death: $10 million
      - Injury: $1 million

    - Number of safety related faults based on historic outage data over a 13.5-year period normalised over the total length of conductor within a section of the network:
      - 0.0034 safety faults / km / year in the 11kV Network
      - 0.0012 safety faults / km / year in the 19kV Network
  - Transformer Risk Cost has been calculated based on the following:
    - Percent of non-compliant back up protection system
    - Likelihood of primary protection non-operation: as per above.
    - Cost of transformer replacement.
    - Number of transformer related faults based on historic outage data over a 13.5-year period normalised over the total length of conductor within a section of the network:
      - 0.0497 transformer faults / km / year in the 11kV Network
      - 0.0216 transformer faults / km / year in the 19kV Network
      - A transformer fault is considered anything that could lead to damage of a transformer.
  - Bushfire Risk Cost has been calculated based on the following:
    - Percent of non-compliant back up protection system
    - Likelihood of primary protection non-operation: as per above.
    - Financial impact of a bushfire
    - Likelihood of bushfire start within a bushfire area.
    - Number of Bushfire related faults based on historic outage data over a 13.5-year period normalised over the total length of conductor within a section of the network:
      - 0.0292 bushfire faults / km / year in the 11kV Network
      - 0.0092 bushfire faults / km / year in the 19kV Network
  - Reliability Risk Cost:
    - Percent of non-compliant back up protection system
    - Likelihood of primary protection non-operation: as per above.
    - VCR impact based on the reduction in customer minutes lost between non-compliance systems and compliance systems:
      - 240 minute reduction for sites located in the metro areas
      - 720 minute reduction for sites located in rural areas
    - Number of transformer related faults based on historic outage data over a 13.5-year period normalised over the total length of conductor within a section of the network:
      - 0.0497 transformer faults / km / year in the 11kV Network
      - 0.0216 transformer faults / km / year in the 19kV Network
- **Extra Benefits**
  - Switching benefit:
    - Cost difference between remote operation and local operation
- **Maintenance and replacement costs:**
  - Recloser and circuit breaker maintenance assumed costs normalised over their expected asset life
  - No replacement costs for the reclosers and protection relays have been used in the calculation.

    - The expected life of a recloser is 15 years.
    - The expected life of a protection relay is 15 years
- **Assessment Period:**
  - 15 years;