Appendix 5.11: Secondary systems-zone substation ASP

Regulatory proposal for the ACT electricity distribution network 2019-24
January 2018

evoenergy

Reference Documents

Document	Version	Date
National Electricity Rules		
National Electricity Law		
Utilities Act (ACT)		
Electricity Distribution Asset Management Policy PO1101		
Asset Management Strategy SM1192		
Asset Management Objectives		
Asset Management System Manual		
PR5017 Recovery and disposal of reclaimed network assets		
SM4606 Environmental PCB Management Plan		
Secondary Systems Strategy		

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Glossary

Term	Definition
AEMC	Australia Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASP	Asset Specific Plan
CAPEX	Capital Expenditure
CB	Circuit Breaker
CT	Current Transformer
FMEA	Failure Mode and Effects Analysis
HV	High Voltage
IED	Intelligent Electronic Device
kV	Kilovolt
LV	Low Voltage
MTBF	Mean Time Between Failures
NER	National Electricity Rules
NSP	Network Service Providers
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
OPGW	Optical Ground Wire
PoF	Probability of Failure
PoW	Program of Work
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
UFLS	Underfrequency Load Shedding
VT	Voltage Transformer

NOTE

All analysis has been undertaken using 2017/18 real dollars unless otherwise stated. Budgeted expenditure for CAPEX & OPEX excludes indirect costs.

Document Purpose

This document is an Asset Specific Plan (ASP). It specifies the activities and resources, responsibilities and timescales for implementing the Asset Management Strategy and delivering the Asset Management Objectives for a specific asset class. In conjunction with the other ASPs, it forms Evoenergy's Asset Management Plan, which describes the management of operational assets of the electricity distribution system.

Detailed in this document are the systematic and coordinated activities and practices whereby Evoenergy manages the asset class in an optimal and sustainable manner. Associated asset condition data, performance data, risks, and expenditure are presented and assessed over the asset life cycle for the purpose of achieving the organisational strategic plan.

As part of the assessment of asset management options, a recommended asset strategy is presented with associated Capital expenditure and Operational expenditure forecasts, including a 10 year budget forecast, for consideration by Evoenergy management.

This document has been developed based on good practice guidance from internationally recognised sources, including the Global Forum on Maintenance and Asset Management (GFMAM) and the Institute of Asset Management (IAM). It has been specifically developed to comply with relevant clauses of ISO55001.

Audience

This document is intended for internal review by Evoenergy management and staff. As part of legislative, regulatory and statutory compliance requirements, the audience of this document is extended to relevant staff of the ACT Technical Regulator and the Australian Energy Regulator.

1 Executive Summary

This Asset Specific Plan provides details of the Asset Management Plan specific to a particular asset class, and is an important part of the line-of-sight management of assets from the corporate objectives and strategy level down to the work execution level. For details of the asset management strategy, refer to the Asset Management Strategy document. For details of how the policies, principles and strategies from the asset management policy and strategy align with the ASPs that form the overall Asset Management Plan, refer to the Asset Management Objectives document.

Zone substation protection assets are located in Evoenergy zone substations and are used to detect and isolate faulty electrical equipment within the substations and detect and isolate faults which occur on any connected transmission lines or distribution feeders. The protection systems ensure reliable operation of the network by isolating faulty sections of the network, and ensure the safety of our staff and the community. The correct operation of the protection systems limits the impact of faults on system stability and any potential damage to network infrastructure.

Zone substation protection must meet the requirements of regulatory authorities such as the Australian Energy Regulator (AER) as outlined in the National Electricity Rules (NER), and the requirements in the ACT Utilities (Technical Regulations) Act 2014.

This ASP adopts a risk-condition based approach in accordance with Evoenergy strategic direction to determine the optimal strategy to maintain and replace zone substation protection assets over their lifetime. This approach considers alignment of secondary protection asset maintenance with the frequency of the primary equipment being maintained, and replacing assets based on their condition rather than age alone.

Accordingly, the condition of various types of zone protection assets has been determined as the key criterion that underpins risk-condition based scenario planning analysis for the 2019-2024 regulatory period to choose the most viable option from:

- Option 0: Do Nothing. This option does not entail any maintenance or replacement and basically is a run to fail strategy that increases risk exposure from $37M in the current 2017 year to $103M at the end of the regulatory period, year 2024.
- Option 1: Existing Strategy at Current Expenditure Level. This option uses a selective age-based replacement strategy maintaining the current annual CAPEX budget of $600k over each year of the regulatory period to 2024 and an annual OPEX of $500k. The current asset maintenance interval of three years is retained. This strategy increases risk exposure from current levels of $37M to $50M by year 2024.
- Option 2: Reduce Cost. This option focuses on OPEX cost reduction. The asset maintenance is aligned with the primary equipment maintenance interval of four years for static and electromechanical protection assets and eight years for numerical protection assets. This option retains the current selective age-based replacement strategy, as our analysis shows excessive risk if asset replacements are reduced. This strategy increases risk exposure from $37M in 2017 to $48M by year 2024.The annual OPEX budget reduces to $400k and the annual CAPEX is maintained at $600k.
- Option 3: Maintain Risk. This option provides cost optimisation in terms of maintenance based on Option 2 and replaces zone protection assets based on asset health assessments to maintain risk. This strategy maintains the current (2017) risk exposure of $37M at end of the regulatory period, year 2024. The annual OPEX budget is set to $350k and the annual CAPEX investment rises to $1.6M to maintain the risk exposure at the end of the regulatory period 2024 to current levels.

- Option 4: Reduce Risk. This option provides cost optimisation by using the maintenance strategy of Option 2 and replacing zone protection assets based on risk reduction and condition monitoring. This option reduces the risk exposure to $25M by the year 2024.This option retains the annual OPEX levels to $350k as proposed in Option 3 and increases annual CAPEX investment to $3M. This option is viable from a corporate strategic perspective and would require prioritisation of zone transformer protection replacement projects. The commercial benefits and viability of prioritising the CAPEX replacement projects will be provided in individual Project Justification Reports.

Based on the risk-condition approach, cost optimisation benefit, and the health of the assets, this plan recommends Option 3 as the strategy that provides the best cost/benefit while controlling the risk. The optimised program of work budget for CAPEX and OPEX is presented in Table 1.

Total Budget	2019/20	2020/21	2021/22	2022/23	2023/24
CAPEX	**1,660,000**	**1,650,000**	**1,730,000**	**1,590,000**	**1,760,000**
OPEX	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**
Planned Maintenance (OPEX)	200,000	200,000	200,000	200,000	200,000
Unplanned Maintenance (OPEX)	50,000	50,000	50,000	50,000	50,000
Condition Monitoring (OPEX)	100,000	100,000	100,000	100,000	100,000

Table 1: OPEX and CAPEX Optimised Program of Work Budget

The annual CAPEX spend for protection replacement is average of $1.67M with a reduction of the average annual OPEX costs to $350k. OPEX has been reduced compared to the present annual spend of $500k.

The condition monitoring and asset replacement approach to maintain risk at current levels will deliver a viable secondary zone protection asset management plan. The selected option provides the following benefits:

- Cost optimisation of OPEX and CAPEX based on asset condition needs,
- Maintaining overall asset class risk and addressing poor asset health and specific risks in some protection relay makes and models,
- Leveraging opportunities to deploy multifunction protection relays as part of the asset replacement program with additional benefits of condition monitoring of primary and secondary assets, and
- Compliance with the NER requirements and AER's strategic objectives.

It has been identified that some protection systems have unacceptably poor health and these asset require replacement during the regulatory period. These assets include:

- Poor condition feeder protection relays such as NILSEN NILSTAT and SPAJ140C that are beyond their useful life. The poor condition assessment is evident by defect reports and maintenance inspections where significant numbers of relays have failed in service and have not reported relay failure though SCADA and these latent in service faulty protections are not otherwise detectable.
- Static line distance protections beyond their useful life that suffer from calibration drift including H types, RAZFE, 7SL24 and RAZOG distance protections.

- Some ageing zone transformer and busbar protection schemes whose tripping functions have shown to malfunction during maintenance.

This ASP presents targeted program of work for CAPEX replacements targeting systems identified with unacceptably poor health. Each CAPEX replacement project is justified based on various option considerations in a separate Project Justification Reports.

2 Asset Class Overview

This section provides an overview of the strategy and objectives specific to the asset class covered by this ASP, provides details of the assets included and their function, and explores the needs and opportunities specific to this asset class.

This ASP covers the Zone Substation Protection asset class, which lies within the secondary systems asset portfolio. The protection assets within this class are responsible for protecting zone substation primary systems and associated distribution network infrastructure. For details of the asset groups contained within the Zone Substation Protection asset class, refer to section 2.2.

2.1 Asset Class Objectives

The asset class strategy presented in this ASP follows the overall Evoenergy asset management strategy and asset management objectives. The asset class strategy is an integral part of the asset management strategy, with the overall objective to provide safe, reliable and cost effective supply of electricity to customers and compliance with regulatory requirements.

This ASP has been developed in alignment with the asset management strategy and seeks to meet objectives in the following categories:

Responsible

- Achieve zero deaths or injuries to employees or the public
- Maintain a good reputation within the community
- Minimise environmental impacts, for example bushfire mitigation
- Meet all requirements of regulatory authorities, such as the AER as outlined in the NER, and the ACT Utilities (Technical Regulations) Act 2014.

Reliable

- Tailor maintenance and renewal programs for each asset class based on real time modelling of asset health and risk
- Meet network SAIDI and SAIFI KPIs
- Record failure modes of the most common asset failures in the network
- Successfully deliver the asset class Program of Work (PoW) to ensure that the protection operates correctly to disconnect faulty sections in accordance with the NER.

Sustainable

- Enhance asset condition and risk modelling to optimise and implement maintenance and renewal programs tailored to the assets' needs
- Make prudent commercial investment decisions to manage assets at the lowest lifecycle cost
- Integrate primary assets with protection and automation systems in accordance with current and future best practice industry standards
- Deliver the asset class PoW within budget.

People

- Proactively seek continual improvement in asset management capability and competencies of maintenance personnel.

That is, the strategy and ASP must be practical in the sense that it can be implemented, must also be flexible enough to satisfy the future requirements of the Evoenergy network, and must be cost effective and efficient with consideration of both technical and human resources.

2.2 Asset Groups

Zone protection assets are classified in terms of the element they protect, such as busbars, lines, transformers and feeders. Table 2 provides a broad-based classification of asset groups within the asset class.

Asset Class	Secondary Systems Zone Substation Protection
Asset Groups	Zone 132kV Busbar Protection Zone 132kV Transmission Line Protection Zone 132kV Power Transformer Protection Zone 11kV Feeder Protection Underfrequency Load Shedding Protection Zone Battery Chargers

Table 2: Asset Classification – Zone Protection Assets

2.3 Asset Functions

The primary function of protection systems is to limit damage to power system apparatus and to protect the community. Whether the fault or abnormal condition exposes the equipment to excessive voltages or excessive currents, shorter fault times will limit the amount of stress or damage that occurs. Protection devices monitor critical system parameters, detect abnormality and initiate isolation of electrical network elements under pre-defined fault conditions. The successful operation of protection schemes is a crucial element in ensuring community safety, the safety of Evoenergy personnel, and the integrity of equipment.

2.3.1 Asset Function Definitions

Evoenergy's zone protection assets have traditionally incorporated electromechanical feeder protection and early generation static relays for zone transformers, busbars, lines and other 11kV feeder protection.

Newer generation numerical protection devices have started to be introduced over the last five years. These devices are classified as multifunction Intelligent Electronic Devices (IEDs). In addition to incorporating the required protection functions, IEDs also provide control, interlocks (safety), metering, alarm and monitoring functions.

The function of assets in this asset class are described in the following sub-sections.

2.3.1.1 Zone 132kV Transmission Line Protection

The following protection functions are considered necessary to protect AAD's 132kV transmission line assets:

A) Line Distance Protection

These devices are traditional 132kV transmission line distance protection schemes. Distance protections operate on impedance principles, on the basis that impedance is a means of identifying distance to the point of fault on the transmission line. On the 132kV network, this type of protection has difficulty in meeting current NER fault clearance time performance standards.

B) Line Differential Protection

Line differential protections operate as a unit protection, and measure difference of currents between the two ends of the line. This function disconnects the circuit only for faults which occur within the protected section of transmission line. This type of protection operates faster and meets current NER performance standards. This is the preferred protection scheme for 132kV line augmentation projects and asset replacement.

C) Back-up Overcurrent Protection

Back-up overcurrent protection for transmission lines comes into effect when the VT supply fails and the line distance protection is out of service. Under VT fail condition, back-up overcurrent protection provides back-up protection for any transmission line faults.

2.3.1.2 Zone 132kV Busbar Protection

The following protection functions are considered necessary to protect AAD's 132kV substation or switching station buses:

A) High Impedance Busbar Protection

These devices provide 132kV zone busbar protection. The high impedance busbar protection operates as a unit protection for faults involving the 132kV bus. For faults external to the protected section, a high impedance circuit in the differential circuit prevents any maloperation.

B) Bus Section breaker back-up Overcurrent Protection

In the event of failure of bus protection to trip or circuit breaker failure, the bus section overcurrent protection provides back-up protection to the bus section breaker.

2.3.1.3 Zone 132/11kV Transformer Protection

The following protection functions are considered necessary to protect AAD's 132/11kV zone substation transformers:

A) Transformer Differential Protection

Transformer differential protections provide rapid unit protection for faults occurring within the HV and LV windings and terminals, based on differential current.

B) Transformer Restricted Earth Fault Protection

Restricted earth fault protections provide rapid unit protection for sensitive earth faults that occur within the transformer windings, based on differential current.

C) Transformer HV back-up Overcurrent Protection

HV back-up protections are three phase overcurrent protections that provide back-up protection to the main transformer differential protection for faults in HV bushings.

D) Transformer Neutral Earth Fault Protection

Neutral earth fault protections are single phase overcurrent protections energised by neutral CTs that provide back-up protection to the main transformer restricted earth fault protection.

E) Transformer Sensitive Earth Fault Protection for Alarms

Sensitive earth fault protections for alarms are single phase overcurrent protections energised by neutral CTs that provide alarms for high resistive earth faults occurring in the 11kV system.

F) Transformer Voltage Regulation Relay

Voltage regulation relay devices are used to regulate transformer voltage and prevent either escalation of voltages to harmful levels or reduction of voltage that would cause damage to appliances.

G) Transformer Buchholz Protection

For incipient faults that eventuate from within the transformer windings as a result of dielectric breakdown or partial discharge of the windings, Buchholz protections are provided for the main transformer, earthing and auxiliary transformers.

H) Transformer Cooling Circuit Protection

Transformer oil and winding temperature detectors are provided, and operate via a temperature regulated cooling control mechanism.

I) 11kV Group Overcurrent and Earth Fault Protection

The 11kV group protections provide primary protections to the 11kV incoming cable and the 11kV switchgear bus to which 11kV outgoing feeders are connected. The group protections back-up the outgoing feeder overcurrent and earth fault protections.

2.3.1.4 Zone 11kV Feeder Protection

A) Feeder Overcurrent Protection

Three phase inverse time overcurrent protections are provided to mitigate single and multiphase short circuits that occur on overhead lines or underground cables.

B) Feeder Earth Fault Protection

Single phase earth fault protection based on inverse characteristics provides expedited fault clearance for faults involving ground, to prevent earth potential rise and damage to assets.

C) Sensitive Earth Fault Protection

Vegetation faults involving conductor and ground result in high resistance and low fault current that are generally not picked up by normal earth fault protections. Sensitive earth fault protection provides mitigation against such faults.

D) Translay Feeder Protection

Translay unit differential protections based on differential current sensing are provided between zone and distribution substation where a sufficient grading margin between inverse time overcurrent protections cannot be achieved.

2.3.1.5 Underfrequency Load Shedding Scheme

Suitably graded load shedding schemes based on underfrequency are installed in zone substations to shed loads in accordance with AEMO and Transgrid’s strategic requirement as a response to a major system disturbance adversely affecting the frequency response of the power system.

2.3.1.6 *Battery Chargers*

Battery chargers are provided for energising DC station batteries that feed secondary system devices in the substation.

2.4 Needs and Opportunities

Traditional Evoenergy protection schemes belong to the older generation of electromechanical and static protection. Many of the traditional complex protection schemes are comprised of a combination of discrete protection devices and timing devices to achieve the level of protection required. With the advent of modern numerical multifunction protection devices, there is an opportunity to combine discrete static or electromechanical schemes into single multifunction assets. This provides opportunities to gradually rationalise assets over a period of time. With the ability to reduce the number of assets due to such a rationalisation process, and the increased levels of protection provided by the new devices, one of the conditions for the accelerated replacement of protection assets is triggered.

Protection relay performance has a profound effect on the safety and reliability of the electricity network. In addition to compliance with the NER, the modern trend for protection also imposes stringent requirements on the need to provide information for the analysis of abnormalities that occur in the power system. Modern protection systems meet the NER requirements and will benefit AAD by also providing additional business efficiencies through automated condition monitoring of the network and primary systems.

The philosophy of combined protection and substation automation, whilst providing a significant opportunity for asset rationalisation, includes asset condition monitoring as the single biggest benefit that will reduce the risk profile for the assets and avoid the cost of asset maintenance over a period of time.

Thus the need to replace assets is based on a risk and condition monitoring philosophy that would provide the organisation with an optimal compromise of asset replacement based on condition deterioration, and maximise returns through the reduced cost of maintenance over the lifetime of the asset.

2.4.1 Needs

The risk associated with zone substation protection relays in their current condition is $37M per annum as of 2017. The most significant element of risk is the reliability consequence associated with a protection system failing to operate during a genuine fault due to the malfunction of the protection relays. This risk can result in a number of different outcomes, including explosive failure or damage to associated primary assets, cascading outages affecting other parts of the network, extended outages to customers, and offloading generation.

The overarching need of protection asset management is to ensure asset maintenance and asset replacement maintains risk exposure at an acceptable and manageable level. The current risk is projected to increase from $37M to $50M by the year 2024 as a result of worsening overall network reliability.

With our aim to maintain current levels of system performance and risk, we propose a baseline risk exposure of $37M per annum to be maintained for risks associated with zone substation protection relays.

2.4.2 Opportunities

2.4.2.1 Optimised Maintenance

With asset maintenance there is an opportunity to optimise maintenance programs, both in the way tasks are performed during maintenance and with the frequency of maintenance. This ASP contains options for different maintenance regimes and consideration of the least cost option to maintain risk at the proposed risk baseline level.

Optimising maintenance will be further possible as older static protection relays are replaced with modern numerical protection, as new relays have automated condition monitoring features, require less frequent maintenance, and are therefore easier and less costly to maintain.

2.4.2.2 Combined Protection and Control with Automated Condition Monitoring

Installing modern multifunction numerical relays will also provide added value by delivering the following:

- Combined protection and control in a single device
- More comprehensive reporting of alarms and indications for system operations
- Automated condition monitoring of the secondary systems and associated primary equipment.

This added value through enhanced protection and control capabilities and automated condition monitoring can deliver substantial supplemental benefits for operations and reducing maintenance expenditure, and opportunities should be sought for the installation of modern numerical relays where possible.

2.4.2.3 Early Retirement of Small Make/Model Protection Relay Families

Within the Evoenergy asset base there are a number of smaller populations of particular protection relay make/model families. Reducing the range of different equipment through the early retirement and replacement of smaller make/model family populations will reduce maintenance costs and eliminate the cost of maintaining staff competencies for working on these smaller populations. Opportunities should be sought for the early retirement and optimising of the asset base.

While asset condition remains the primary driver supporting protection replacement projects, the advantages posed by installing modern numerical relays and optimising maintenance needs to be considered in the Project Justification Report cost benefit analysis for asset replacements.

2.5 Associated Asset Classes

The operation of protection devices is associated with other asset classes. Specifically, this involves inputs from current transformers, voltage transformers, and other discrete inputs from devices interfacing to electrical equipment.

Typically, current based protections are overcurrent, earth fault, transformer and line differential protections. Line distance protections seek inputs from both current and voltage transformers.

Overvoltage, undervoltage and frequency based protections seek inputs from voltage transformers.

Station batteries provide the auxiliary supply to power up the electronic circuits.

Numerical protections with measuring properties provide interface back to SCADA/ADMS to read the power system parameters inclusive of fault values and circuit breaker condition monitoring information.

3 Asset Base

This section provides details of Evoenergy's current asset base for assets that are a part of this asset class, including the current age and condition profiles of the assets and the projected asset count.

3.1 Asset Base Summary

Table 3 gives details of Evoenergy's in-service or system spare zone protection assets as at April 2017.

Asset Type	Quantity	Design Life (yrs)	Average Age (yrs)	Oldest Age (yrs)
Busbar Protection	64	20	33	41
Transmission Line Protection	93	20	29	38
Zone Substation Feeder Protection	564	20	24	38
Zone Transformer Protection Assets	174	20	27	31
Grand Total	**895**	**20**	**25**	**41**

Table 3: In-service Assets

3.2 Asset Service Life Expectancy

The design life of assets is 30 years for static zone protection assets and 20 years for numerical protection assets. The useful life may be less than or greater than the design life, which can depend on quality of manufacturing, installation, maintenance and operational conditions.

Over the last five years, numerical protection with self-supervision features and seamless integration with SCADA and communication systems has been extensively deployed in the network at the Civic, East Lake, Angle Crossing, and Tennant zone substations, and at the Bruce switching station. These assets, in addition to the protection and data reporting features, provide extensive condition monitoring of primary and secondary assets. These assets were deemed at the end of their useful life both from a condition and obsolescence perspective. The replacement met the key criteria set out in accordance with the NER.

3.3 Asset Age Profile

Figure 1 shows the age profile of the zone protection assets.

The asset age profile shows there are a large number of assets over 25 years of age and some assets beyond the expected life of 30 years. In the next regulatory period increasing numbers of assets will reach end of life condition and will require replacement. This need for replacement is further demonstrated in the asset condition profile in section 3.4, where asset health is identified as poor for some models of equipment.

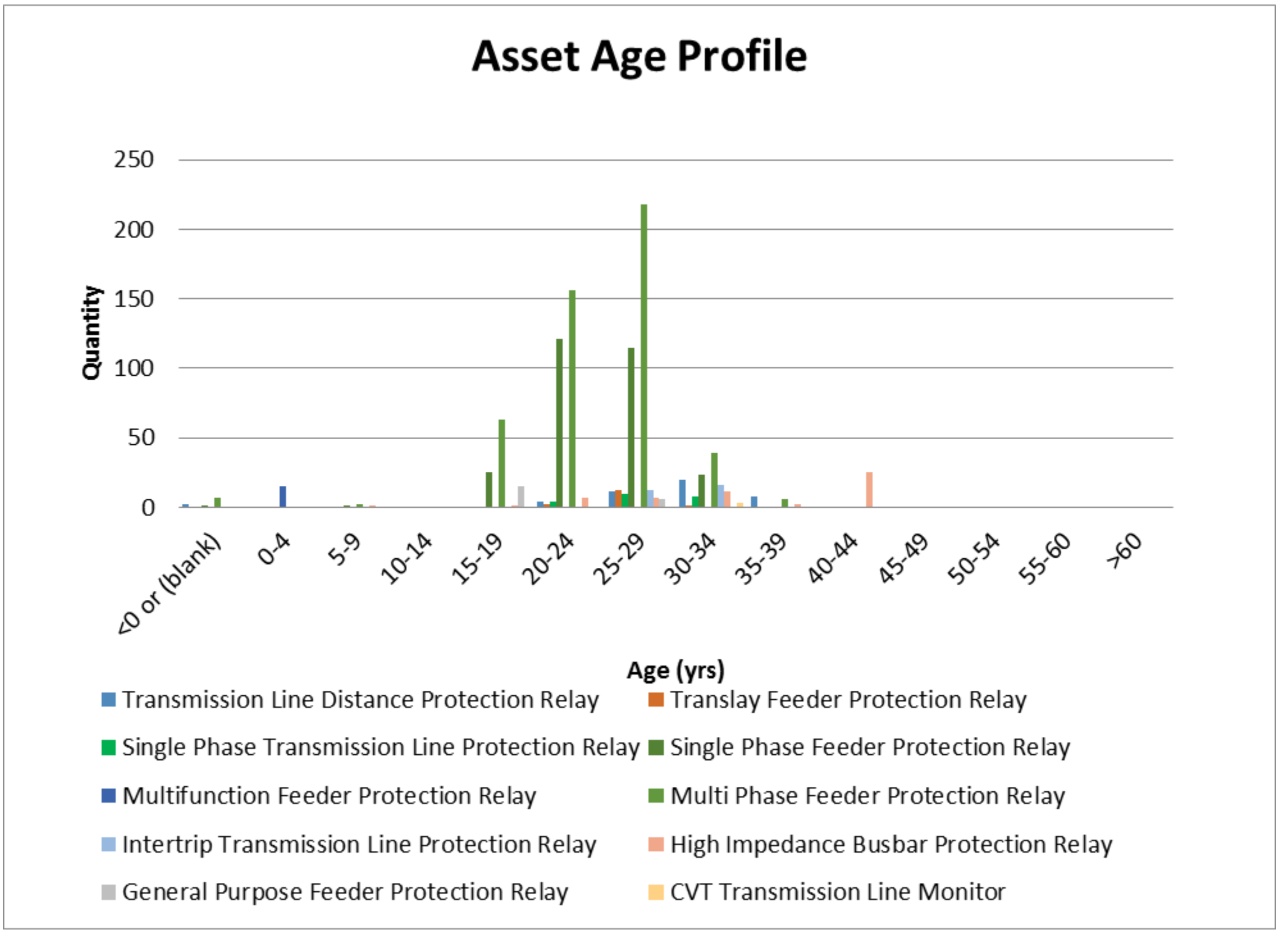

Figure 1: Age Profile of Zone Protection Assets

3.4 Asset Condition Profile

The asset health assessment has been performed by applying an age and condition based deterioration curve for individual assets and averaging the condition for assets within each manufacturer/model protection relay family.

Protection relay condition assessments are made during the planned maintenance inspection cycle with the following factors considered: calibration drift, tripping function, power supply calibration, indications and controls functional. The condition assessment is via a condition scorecard and formula within Cityworks. Fault and defect history is also captured in Cityworks.

Condition assessment and fault history is analysed across protection relay families and where demonstrated performance issues are evident, a deterioration factor has been applied to the health assessment.

Table 4 gives details of the current condition of the zone protection assets.

Manufacturer	Model	Quantity (2018)	Average Health (2018)	Remarks
Transmission Line Distance Protection Relay		**45**		
ABB	RELZ100	2	Poor	NER compliance issues with meeting fault clearance time - replace
AREVA	P443211A4N0320J	1	Good	
ASEA	RAZFELINEDISTT1	8	Poor	NER compliance issues with meeting fault clearance time - replace
ASEA	RAZOGLINEDISTAN	2	Poor	NER compliance issues with meeting fault clearance time - replace
REYROLLE	HTYPELINEDIST	6	Poor	NER compliance issues with meeting fault clearance time - replace
SIEMENS	7SL2410-3AA5	12	Poor	Calibration issues NER compliance issues with meeting fault clearance time - replace
SEL	SEL411L	7	Excellent	
SCHNEIDER	MICOM P545	7	Excellent	
Translay Feeder Protection Relay		**15**		
GEC	HO4	15	Fair	
Single Phase Transmission Line Protection Relay		**33**		
GEC		13	Good	
GEC	MCGG21(125V)	10	Good	
GEC	METI11	3	Good	
GEC	MCGG22(125V)	7	Good	
Busbar Protection		**64**		
GEC	FV2	4	Fair	
GEC	FAC34	50	Fair	
GEC	MFAC	10	Excellent	
Transformer Protection Relay		**174**		
REYROLLE	4C21-Dupbias	46	Fair	Replace as assets reach end-of-life / poor condition / obselecence
ASEA	RADSB	33	Fair	Replace as assets reach end-of-life / poor condition / obselecence
GEC	VAJH	65	Fair	Replace as assets reach end-of-life / poor condition / obselecence
EMAIL	2K153	22	Fair	Replace as assets reach end-of-life / poor condition / obsolescence
SEL	SEL487E	4	Excellent	
SCHNEIDER	MICOM P687	4	Excellent	
Single Phase Feeder Protection Relay		**262**		
EMAILELECTRONIC		68	Fair	
GEC	MCGG21(125V)	4	Good	Targeted replacement for relays that are part of protection schemes containing poor condition ABB-SPAJ140C and/or Nilsen Nilstat relays
GEC	CDG21AMLZ1AF137	46	Fair	
GEC	MCSU (125V0.1-9.	90	Fair	
GEC	MCGG22(32V)	15	Fair	
GEC	CAG12/VT11(32V)	1	Fair	
GEC	CDG23AF1169E5	4	Fair	
GEC	CDG11AF42A	3	Fair	
GEC-ALSTOM	MCGG22(125V)	28	Fair	
SCHNEIDER	P120	3	Good	
Feeder Protection		**302**		
ABB	ABB-SPAJ140C	84	Poor	Assets failing regularly
NILSEN	NILSTAT	84	Poor	Assets failing regularly
SEL	SEL351A	67	Excellent	
MICOM	MICOM P145	67	Excellent	

Table 4: Current Zone Protection Asset Condition

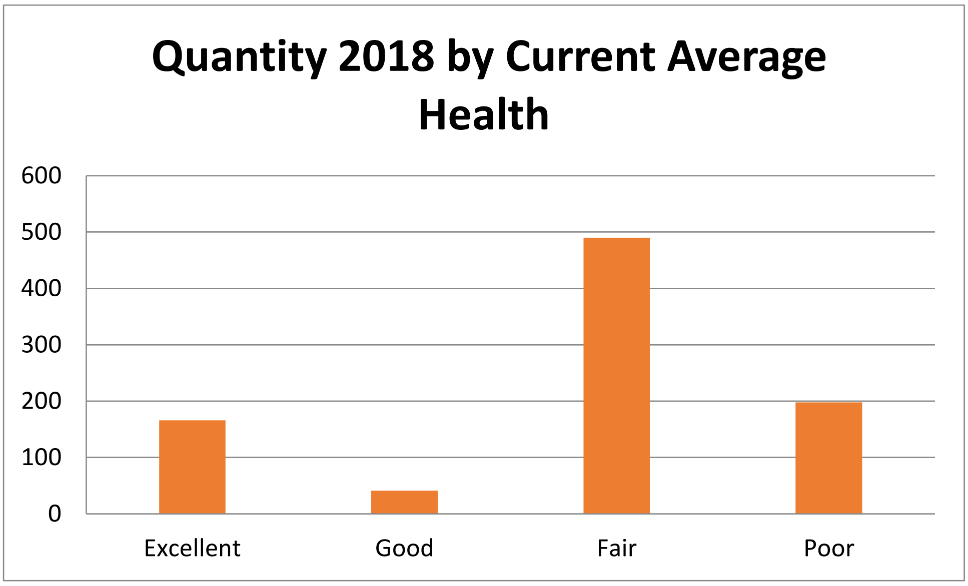

Figure 1: Current asset health condition

Based on the current health condition as detailed in Table 4, the following assets have unacceptable poor condition and need to be managed by the preferred asset class strategy:

- Poor condition feeder protection relays such as NILSEN NILSTAT and SPAJ140C. This poor condition assessment is evident by defect reports and maintenance inspections where significant numbers of relays have failed in service and have not reported relay failure though SCADA and these latent in service faulty protections were not otherwise detectable. This represent an unacceptable risk to the network and safety.
- Static line distance protections that are steadily losing their calibration such as H types, RAZFE, 7SL24 and RAZOG distance protections.
- Some ageing zone transformer and busbar protection schemes whose trip contacts are malfunctioning.

3.5 Projected Asset Count

The projected asset count is an estimate of the number of zone protection assets by year. The estimate includes asset additions and retirements through estimated network augmentation and asset retirements over the period. Refer to Figure 2 for details.

The asset quantity reduces gradually over a period of time as more modern single numerical multifunction devices replace multiple discrete devices some of which are in the form of single phase protections. In some cases one multifunction device can replace up to five decrete devices.

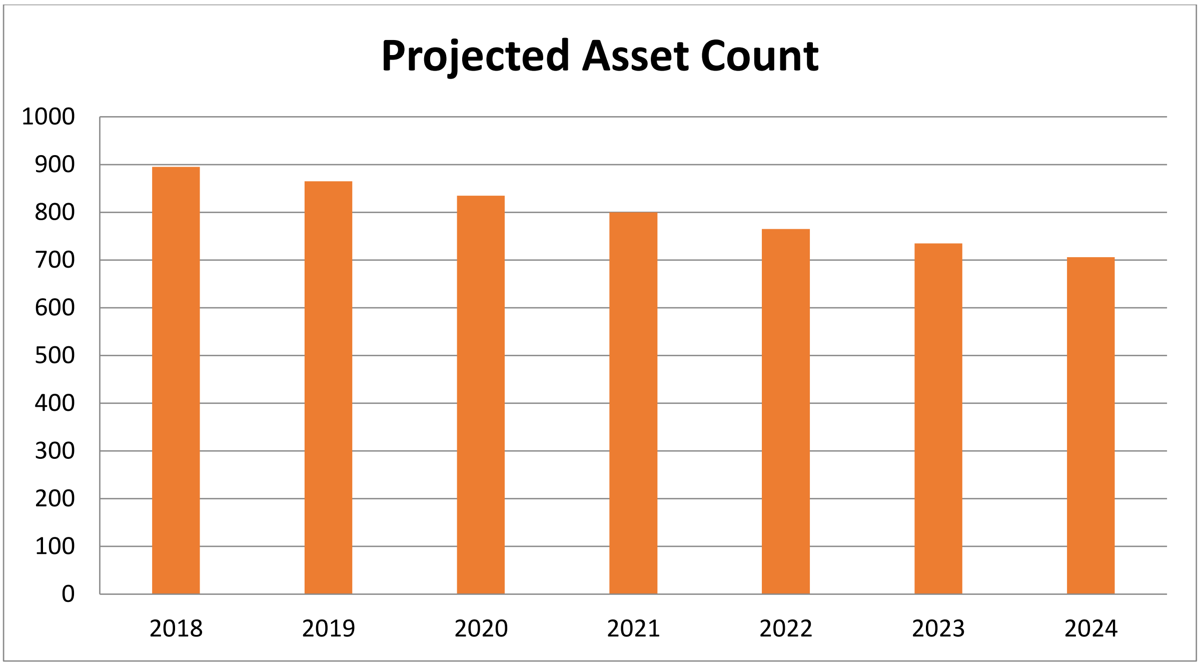

Figure 2: Projected Asset Count of Zone Protection Assets

3.5.1 Network Augmentation and Infrastructure Development

The following network augmentation projects affect the asset class population.

3.5.1.1 Underfrequency Load Shedding Schemes

Underfrequency load shedding schemes installed at various zone substations.

3.5.1.2 Duplicatation of Transmission Line Protection and Line Differential Protection

Currently some zone substations have single 132kV line protections installed. Duplicate transmission line protection and line differential protection will be installed with planned replacement projects for achieving NER compliance.

4 Asset Performance Requirements

This section details the reliability and performance requirements of the zone protection asset class.

4.1 Failure Modes

This section outlines the Failure Mode and Effects Analysis (FMEA) and deterioration drivers for each asset type. Failure modes, Risk Priority Number (RPN) and cost of failure have been nominated by subject matter experts. This analysis is used to evaluate strategy options for this asset class.

4.1.1 Protection Relays

Once protection relay hardware has reached the end of its useful life, degradation of component characteristics will cause the modules to fail. In addition, environmental factors also drive deterioration or deviation in the performance of electronic components. On that basis, protection relays are characterised by an abrupt condition deterioration curve with respect to their maximum potential life. The failure rate during the rated useful life of the product is fairly low. Once the end of life condition is reached, failure rates of modules increase abruptly.

Table 5 summarises the common failure modes for zone protection assets.

Failure Mode	Failure Cause	Severity	Occurrence	Detection	RPN
Card failure	Relay non-functional. Protection does not operate to clear fault. Fault cleared by either back-up protection or group breaker. Possibility of large scale disconnection of customers.	8	6	5	240
Maloperation due to calibration drift	Relay partially functional. Protection maloperates or fails to operate in one or all phases Feeder could trip when not necessary or not trip at all, relying on back-up protection to operate. Risk of group transformer protection operation that could cause large scale disconnection of customers. Possible damage to primary systems assets, for example power transformers, switchgear, lines and feeders.	8	6	5	240
Output trip relay contact failure	Inability of output contact to energise trip circuit. Protection operates but does not trip to clear fault; back-up protection clears the fault. More customers are disconnected. Possible damage to primary systems assets.	8	6	5	240
Power supply failure	Relay does not power up. Protection not available to clear fault, back-up protection clears fault. More customers are disconnected. Possible damage to primary	8	6	5	240

	systems assets.				
Failure of CB fail schemes to operate or maloperate	Circuit breaker fail protection faulty. Risk of group transformer protection operation that could cause large scale disconnection of customers. Possible damage to primary systems assets.	8	5	5	200

Table 5: Common Failure Modes of Zone Protection Assets

4.1.1.1 Deterioration Drivers for Zone Protection Asset Class

Hardware failures during an asset's life can be attributed to the following causes:

- Design failures

  This class of failures takes place due to inherent design flaws in the system. In a well-designed system this class of failures should make a very small contribution to the total number of failures.

- Infant Mortality

  This class of failures causes newly manufactured hardware to fail. This type of failures can be attributed to manufacturing problems like poor soldering, leaking capacitor etc. These failures should not be present in systems leaving the factory as these faults will show up in factory quality control and factory acceptance tests.

- Random Failures

  Random failures can occur during the entire life of a hardware module. These failures can lead to system failures. Redundancy is provided to recover from this class of failures.

  The following class of failures are classified in this category:

  - Mean Time between failures of components (MTBF).

    MTBF is the average time between failures of hardware modules. MTBF for hardware modules can be obtained from the vendor for off-the-shelf hardware modules. MTBF for in-house developed hardware modules is normally calculated by the hardware team developing the board. Typically, this is 20-30 years for static/numerical protections and 30-40 years for electromechanical protections.

  - Environmental failures and failure in tropical and humid environment.

    This would account for component failures due to temperature variations, tropicalisation and change in the humidity factors.

  - Software issues and mis-configurations.

    This could be as a result of software or firmware upgrades that would affect the overall functioning of the protection scheme.

  - Inappropriate usage and scheme failures.

    Relays implemented are not appropriate for protection scheme.

  - Calibration and deviation from standard operating curves.

    The departure in the relay operating behaviour would be as a result of ageing and generally related to component failures.

4.2 Asset Utilisation

This section details the utilisation level of the assets. Depending on the asset type, the level of utilisation will have a direct impact on asset condition and performance deterioration rates.

4.2.1 Capacity and Capability

The installation of new numerical devices with recent projects (Angle Crossing, East Lake, Civic, Gilmore zone substations and Bruce switching station) provides Energy Networks with immediate detection of failed relays without reliance on scheduled maintenance. This greatly reduces the risk of defective units being in-service and potential maloperation. Numerical protections include the following self-diagnostic features that greatly improve the safety and reliability of the network:

- CT Supervision
- VT Supervision
- Relay health
- Trip circuit supervision.

Data logging also provides performance information, allowing more accurate capture, recording and reporting of real-time and historical asset performance, which is not economically possible with static and electromechanical relays.

In addition, numerical protections provide additional information such as distance to fault and fault currents back to the ADMS. The ADMS utilises fault current information to assist in localisation of fault using a fault predicting algorithm. The distance to fault locating feature will improve restoration times. This effectively ensures increased availability and service capacity to consumers.

However, immediate access to event and relay status data comes at a cost. The cost to Energy Networks will require the upgrade of existing SCADA communications to accommodate increased data transfer from the field to the office so that engineers can access event and relay status data.

4.2.2 Utilisation

Asset utilisation is not directly applicable to protection assets as they do not directly contribute to revenue. They contribute indirectly by providing a safe network, preventing damage to major assets, reducing unplanned outage area and duration and the number of customers off supply in an unplanned outage. When a protection relay is in service, it is 100% utilised.

4.3 Risk and Criticality

This section details the criticality of the zone protection assets and their exposure to risk.

4.3.1 Asset Criticality

Protection systems are critical for reliable operation, asset protection and network safety. Protection devices and systems need to be correctly configured, installed, managed and maintained. Protection devices and schemes limit damage to power system apparatus. Whether the fault or abnormal condition exposes the equipment to excessive voltages or excessive currents, shorter fault times will limit the amount of stress or damage that occurs. Protection devices monitor critical system parameters, detect abnormality and initiate isolation of electrical network elements under pre-defined fault conditions. The successful operation of protection schemes is a crucial element in ensuring community safety, the safety of Evoenergy personnel and equipment.

4.3.2 Geographical Criticality

Primarily protection systems and assets are installed at zone substations and switching stations (132kV and 11kV systems and auxiliary equipment). Zone protection systems interact with a number of major asset types including transformers, switchgear, circuit breakers, busbars, voltage regulators and SCADA systems.

Whilst geographical criticality affects primary equipment due to climatic conditions as they are mounted outdoors, protection relays located in control rooms are relatively unaffected by geographical locations and climatic conditions.

4.3.3 Asset Reliability

Above all, relays must be reliable, dependable and secure. Relays operate continuously by making correct decisions that discriminate between loads and faults, and discriminate between faults that are in the zone of protection and all other faults. Protection reliability is affected by equipment failures and by appropriate application and installation. Determining device reliability is more important for relays that cannot perform self-diagnostics and alarming.

With a maximum potential life of 30 years, the expected service reliability in terms of failure of protective devices inclusive of maloperations is one in one hundred.

5 Asset Management Strategy Options

This section discusses asset class strategies to manage zone protection assets throughout their lifecycle and recommends the preferred option. The preferred asset class strategy supports the business asset management policy, strategy and objectives.

5.1 Option Overview

Asset class strategies are evaluated against their cost, risk, benefits and consideration of trade-offs between capital and operational expenditure to achieve the asset management objectives. The options that have been considered include:

- Option 0 – Do Nothing Strategy
- Option 1 – Existing Strategy at Current Expenditure Level
- Option 2 – Reduce Cost Strategy – OPEX optimisation
- Option 3 – Maintain Risk Exposure Strategy
- Option 4 – Reduce Risk Exposure Strategy.

5.1.1 Option 0 – Do Nothing Strategy

This option assesses the inherent risk rating for the zone protection asset class if no controls or mitigating strategies are in place.

5.1.1.1 Description

This option is the do nothing strategy whereby assets are 'run-to-failure' without planned maintenance or planned replacement. Upon failure, assets are assessed and reactively repaired or replaced as necessary. Typical asset management tasks for this strategy include:

- Operation of critical assets until partial or catastrophic failure
- Corrective maintenance to repair faults
- Reactive replacement to restore unrepairable assets.

5.1.1.2 Cost

This option entails nil OPEX/CAPEX costs. However, a provisional budget of $20,000 has been allowed per annum to account for any unplanned maintenance.

5.1.1.3 Risk

As asset condition deteriorates and assets approach the end of their expected life, their reliability will decrease and the risk exposure of this option will rapidly increase.

Risk summary:

- 11 asset class risks with High Rating, with those assets classified as 'Poor' condition
- Increasing risk exposure due to aging asset population without planned replacement
- Risk cost of catastrophic failure exceeds $6M per failure.

A qualitative risk assessment of this option highlights the inherent risks (no controls) of this asset class and the risk exposure. This is shown in Table 6.

		Inherent Risk				
Likelihood	Almost Certain					
	Likely	Low 17	Medium 2	High 4		
	Possible	Low 1	Medium 1	Medium 6	High 3	
	Unlikely	Low 4	Low 1	Medium 1	Medium 1	High 4
	Rare					
		Negligible	Minor	Moderate	Major	Severe
		Consequence				

Table 6: Qualitative Risk Assessment – Option 0

A quantitative risk assessment for this option has been modelled to estimate the risk exposure and is shown in Figure 3.

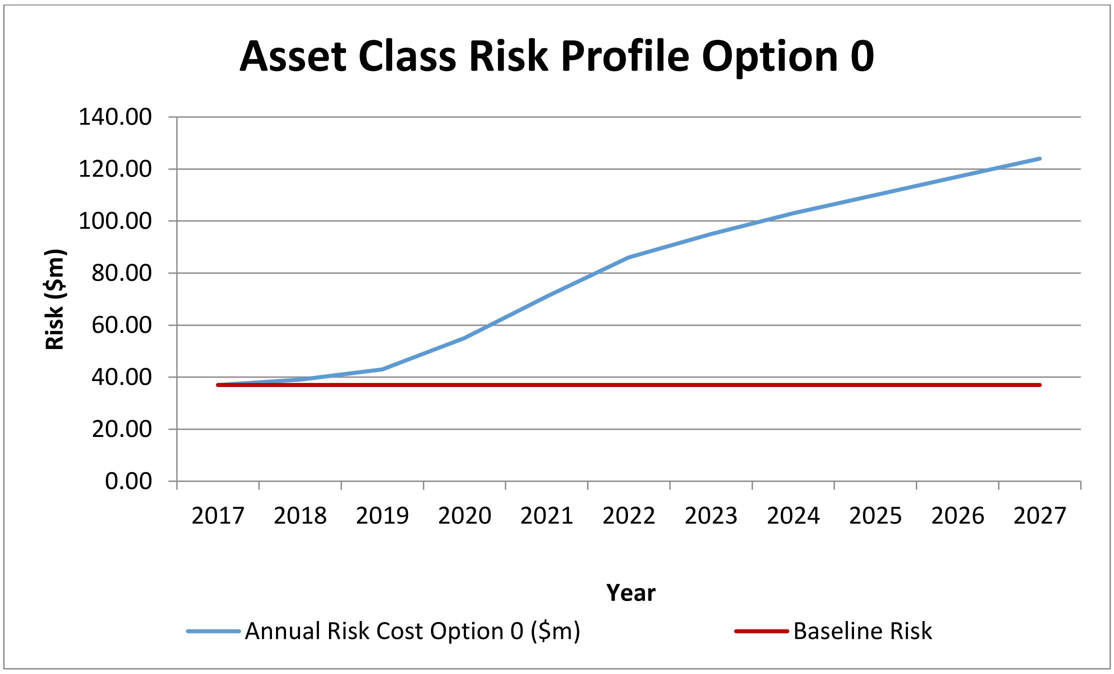

Figure 3: Risk-Cost Analysis – Option 0

5.1.1.4 *Option Assessment*

Whilst the run to fail option provides economic benefits in terms of avoided OPEX and CAPEX expenditures, the increase in risk exposure from current levels of $37M in 2017 to $103M in 2024 at the end of the regulatory period represents a significant departure from current risk exposure.

The run to fail strategy does not provide any benefits from a reliability perspective. There would be an unavoidable increase in unplanned outages leading to long intervals of power disconnection, safety issues, and inconvenience to customers. Evoenergy would be impacted negatively through reputational loss, loss of reliability and revenue. In addition, this option would worsen SAIFI/SAIDI numbers and result in loss of STPIS revenue incentives.

This option is rejected given the risk it poses in terms of reliability and safety, the two core objectives of Energy Network's strategic vision.

5.1.2 Option 1 – Existing Strategy at Current Expenditure Level

This option assesses the existing asset class strategy for the management of zone protection assets, maintaining current CAPEX and OPEX levels.

5.1.2.1 Description

In this option, the current CAPEX strategy of selective age-based replacement is considered along with a three yearly protection maintenance interval.

5.1.2.2 Cost

In this option, the current CAPEX spending level of $600k per annum is retained for selective age-based replacement. The current OPEX spending level of $500k per annum is also retained based on a three year protection asset maintenance interval.

5.1.2.3 Risk

Retaining the current expenditure level for replacing zone protection assets will expose Evoenergy to an increasing level of risk due to a large number of assets showing poor future health. Current expenditure levels will not meet the need to replace assets and a large number of assets will reach a critical health level at the end of the regulatory period in 2024.

Risk summary:

- A substantial increase in the asset risk profile from $37M in 2017 to $50M in 2024 which could adversely impact the SAIFI/SAIDI and impede the STPIS benefits
- Substantial deterioration of condition of assets failing regularly and replaced like for like
- Systems currently do not comply with NER requirements for transmission protection.

The exposed asset class risk ratings for this option at the end of the regulatory period (2024) are shown in Table 7.

Likelihood		Option 1 Risk				
	Almost Certain					
	Likely					
	Possible	Low 17	Medium 2	Medium 4		
	Unlikely	Low 5	Low 1	Medium 7	Medium 4	
	Rare		Low 1		Medium 5	Medium 6
		Negligible	Minor	Moderate	Major	Severe
		Consequence				

Table 7: Qualitative Risk Assessment – Option 1

A quantitative risk assessment for this option has been modelled to estimate the risk exposure and is shown in Figure 4.

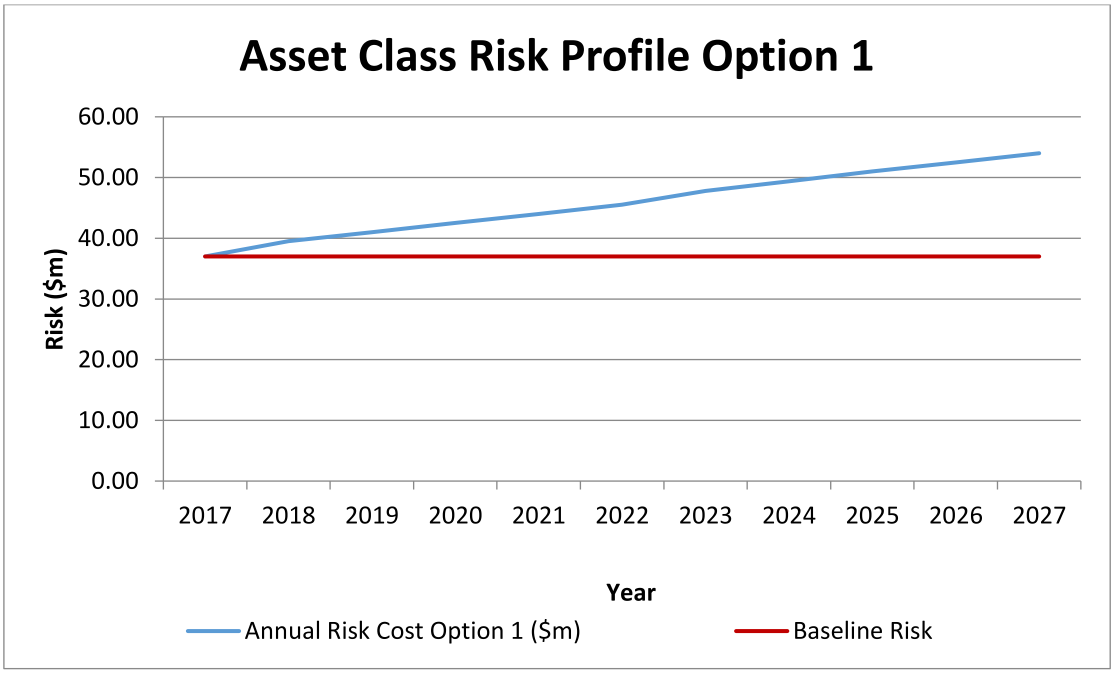

Figure 4: Risk-Cost Analysis – Option 1

5.1.2.4 *Option Assessment*

The risk exposure of this option increases to $50M by the year 2024. Whilst this option limits the increase of risk compared to the Do Nothing option, it still results in an increased risk exposure of $13M above the baseline risk of $37M, and increases the overall probability of customers experiencing unplanned outages.

This option is rejected given the risk it poses. To alleviate the level of risk exposure, additional CAPEX investment to replace protection assets with average to poor condition would be necessary to reduce unplanned outages to energy customers.

5.1.3 Option 2 – Reduce Cost

This option discusses opportunities to reduce OPEX for this asset class by aligning protection maintenance with maintenance intervals for primary equipment such as circuit breakers. It considers opportunities to reduce costs when compared to the existing strategy (Option 1).

5.1.3.1 Description

This strategy option reduces the OPEX costs compared to the existing asset class strategy by optimising maintenance intervals and maintaining the existing annual average CAPEX levels.

This strategy includes the following tasks:

- Increase maintenance intervals for static and electromechanical protections from 3 years to 4 years, in alignment with primary equipment;
- Increase maintenance interval for numerical protections to 8 years;
- Maintain the annual average CAPEX based on selective asset age-based replacement.

5.1.3.2 Cost

The annual CAPEX level remains at $600k, and the annual OPEX level reduces from $500k to $400k.

5.1.3.3 Risk

This approach results in:

- An increase in the asset risk profile from $37M in 2017 to $48M in 2024 which would continue to impact the SAIFI/SAIDI and impede the STPIS benefits;
- Systems currently do not comply with NER requirements for transmission protection.

The exposed asset class risk ratings for this option at the end of the regulatory period (2024) are shown in Table 8.

Likelihood	Option 2 Risk				
Almost Certain					
Likely					
Possible	Low 17	Medium 2	Medium 4		
Unlikely	Low 5	Low 1	Medium 7	Medium 4	
Rare		Low 1		Medium 5	Medium 6
Consequence	Negligible	Minor	Moderate	Major	Severe

Table 8: Qualitative Risk Assessment – Option 2

A quantitative risk assessment for this option has been modelled to estimate the risk exposure and is shown in Figure 5.

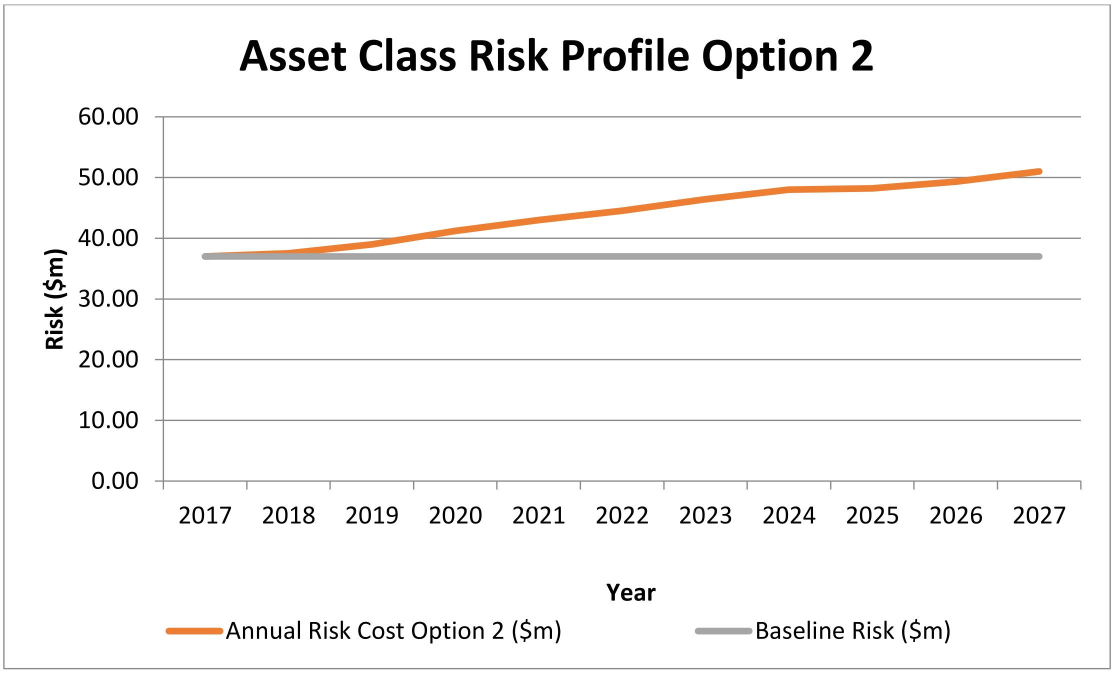

Figure 5: Risk-Cost Analysis – Option 2

5.1.3.4 Option Assessment

The risk exposure of this option increases to $48M by the year 2024, similar to the existing strategy. Whilst this option limits the increase of risk compared to the Do Nothing option, and reduces OPEX costs compared to the existing strategy, it still results in increased risk exposure approximately $11M above the baseline risk of $37M, and increases the overall probability of customers experiencing unplanned outages.

This option is rejected given the risk it poses. To alleviate the level of risk exposure, additional CAPEX investment to replace protection assets with average to poor condition would be necessary to reduce risks of maloperation and resulting unplanned outages to customers.

Whilst this option is rejected, the optimised OPEX has demonstrated little increase in risk exposure and the optimised maintenance is included with Option 3.

5.1.4 Option 3 – Maintain Risk Exposure

This option considers a strategy to maintain the asset class risk exposure at the current level, taking 2017 as the baseline year. In terms of developing a viable asset renewal and maintenance plan, the following aspects form the core strategy that would assist in maintaining the risk exposure at $37M at the end of the regulatory period 2024:

- Optimal increase in CAPEX investment to replace assets that are in average to poor condition
- Optimised maintenance strategy as proposed in Option 2.

5.1.4.1 Description

This option maintains the current 2017 levels of risk exposure for the zone protection asset class. This is achieved by an increased asset renewal program based on asset condition. The condition based replacement option utilises the current health of the assets and identifies ones that are either failing regularly or are experiencing excessive calibration drift. There are a large number of assets showing poor future health and an increase in CAPEX investment is therefore required to maintain risk at the current level.

The OPEX costs are optimised by aligning maintenance of protection relays with the primary equipment cycle of 4 years for most of the protection relays, with numerical relays being maintained every 8 years.

The condition or performance of any two assets of the same make, model, and chronological age, can differ significantly. Because not all assets deteriorate at a standard uniform rate across the asset class, this strategy manages risk along with optimised cost of OPEX and CAPEX across the network by deferring part of the replacement after the regulatory period 2019-2024.

5.1.4.2 Cost

The average CAPEX investment is projected to be $1.6M per annum, with an optimised annual OPEX cost of $350k. This represents an increase in CAPEX of $1.0M per annum with a reduction in OPEX of $150k per annum, based on current expenditure levels.

5.1.4.3 Risk

This approach results in:

- Maintaining the current levels of risk exposure of $37M through to the year 2024;
- Complete compliance with NER requirements with automated condition monitoring of primary and secondary equipment.

The exposed asset class risk ratings for this option at the end of the regulatory period (2024) are shown in Table 9.

		Option 3 Risk				
Likelihood	Almost Certain					
	Likely					
	Possible	Low 17	Medium 1	Medium 1		
	Unlikely	Low 5	Low 1	Medium 1	Medium 3	
	Rare		Low 1		Medium 1	Medium 4
		Negligible	Minor	Moderate	Major	Severe
		Consequence				

Table 9: Qualitative Risk Assessment – Option 3

A quantitative risk assessment for this option has been modelled to estimate the risk exposure and is shown in Figure 6.

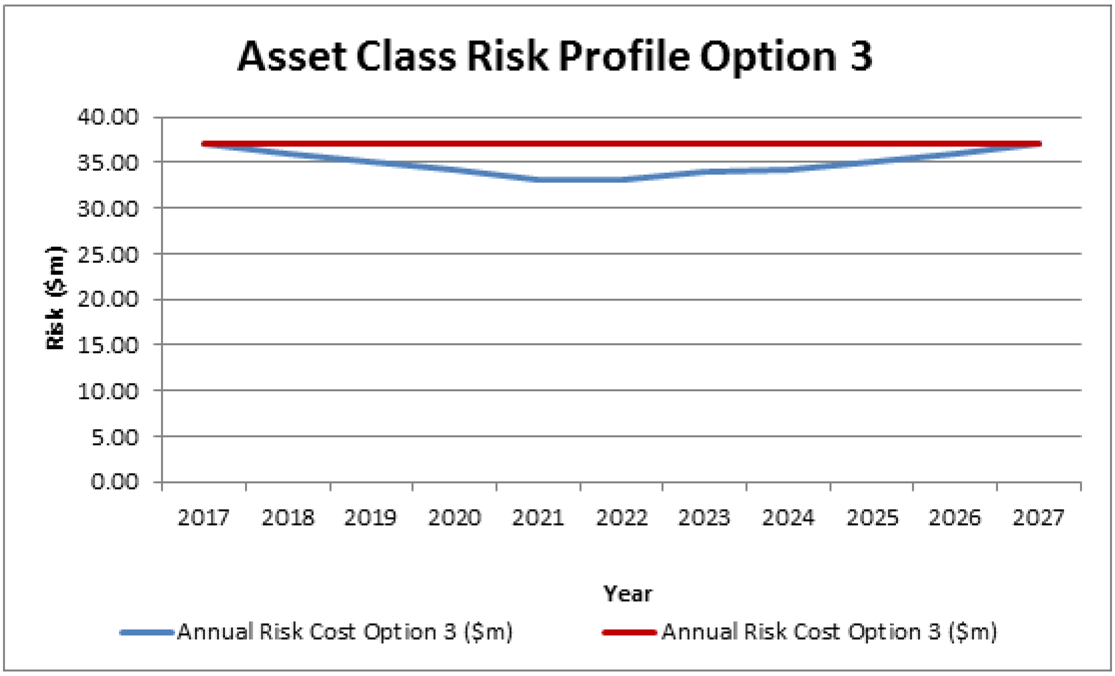

Figure 6: Risk-Cost Analysis – Option 3

5.1.4.4 *Option Assessment*

This option maintains risk exposure at the current level of $37M for the regulatory period 2019-2024. This strategy implies that the increased annual CAPEX investment of $1.0M will result in maintaining the risk that would otherwise increase by $13M to $50M under current expenditure levels (Option 1). This is a prudent investment to contain risk to current levels. An additional benefit of implementing this strategy is maintaining the current levels of SAIFI/SAIDI and STPIS benefits due to avoided cost of unplanned outages and STPIS penalty.

The increased capital investment in maintaining the risk exposure is therefore a viable option as it assists in maintaining power system reliability to Evoenergy customers at current levels. The commercial benefits and viability of prioritising the CAPEX replacement projects will be provided in individual Project Justification Reports.

5.1.5 Option 4 – Reduce Risk Exposure

This option considers a strategy to reduce the asset class risk exposure from current 2017 levels and assesses the resultant cost. In terms of developing a viable asset renewal and maintenance plan, the following aspects form the core strategy that would assist in reducing the risk exposure to $25M:

- A radical increase in CAPEX investment to replace assets that are in average to poor condition and all zone substation transformer protection assets;
- Optimised maintenance strategy as proposed in Option 2.

5.1.5.1 Description

This option reduces the risk exposure compared to current 2017 levels for the zone protection asset class. This is achieved by an accelerated asset renewal program based on asset condition. Ageing zone transformer protection assets that have become obsolete have been considered for pre-emptive replacement.

The condition based replacement option utilises the current health of the assets and identifies ones that are either failing regularly or are experiencing excessive calibration drift.

Furthermore, the OPEX costs are optimised by aligning maintenance of protection relays with the primary equipment cycle of 4 years for most of the protection relays, with numerical relays being maintained every eight years.

The condition or performance of any two assets of the same make, model, and chronological age, can differ significantly. Because not all assets deteriorate at a standard uniform rate across the asset class, this strategy optimises reduction of risk along with optimised cost of OPEX and CAPEX across the network by deferring part of the replacement after the regulatory period 2019-2024.

5.1.5.2 Cost

The average CAPEX investment is projected to be $3.0M per annum, with an optimised annual OPEX cost of $300k.

5.1.5.3 Risk

This approach results in:

- Reducing the current levels of risk exposure from $37M to $25M;
- Complete compliance with NER requirements with automated condition monitoring of primary and secondary equipment.

The exposed asset class risk ratings for this option at the end of the regulatory period (2024) are shown in Table 10.

		Option 4 Risk				
Likelihood	Almost Certain					
	Likely					
	Possible	Low 17	Medium 1	Medium 1		
	Unlikely	Low 5	Low 1	Medium 1	Medium 1	
	Rare		Low 1		Medium 1	Medium 1
		Negligible	Minor	Moderate	Major	Severe
		Consequence				

Table 10: Qualitative Risk Assessment – Option 4

A quantitative risk assessment for this option has been modelled to estimate the risk exposure and is shown in Figure 7.

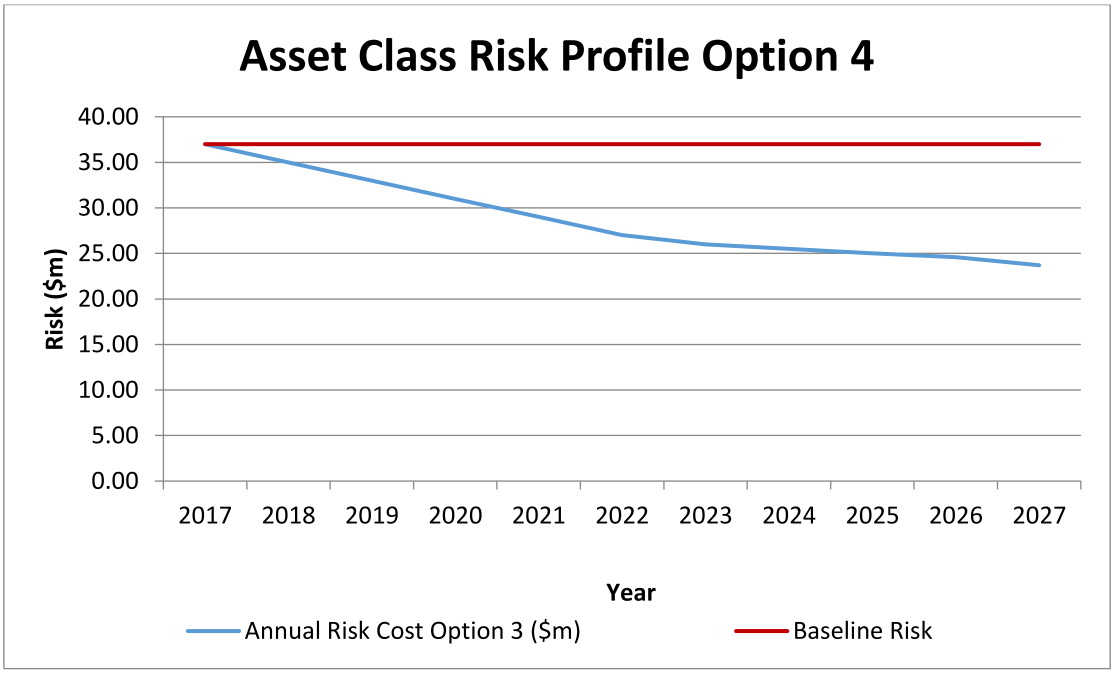

Figure 7: Risk-Cost Analysis – Option 4

5.1.5.4 Option Assessment

This option reduces the risk exposure to $25M for the regulatory period 2019-2024. By the end of the regulatory period, the risk exposure would have otherwise increased by approximately $25M to $50M (Option 1).

The CAPEX investment provides the following tangible benefits:

- Power supply reliability improvement and minimised customer interruptions

- Reduction in SAIFI/SAIDI
- Increase in the STPIS benefits to Evoenergy's accumulated revenue in the regulatory period.

The additional increase in CAPEX from a commercial perspective is largely offset by the additional income resulting from increased STPIS benefits and increased power reliability to the customers. Therefore this option is viable from a corporate strategic perspective and would require prioritisation of zone transformer protection replacement projects. The commercial benefits and viability of prioritising the CAPEX replacement projects will be provided in individual Project Justification Reports.

5.2 Option Evaluation

In order to assess the most optimal zone protection asset replacement strategy, a condition and risk-cost based modelling approach has been conducted using the RIVA Asset Management modelling tool for the various scenarios.

5.2.1 Options Cost and Risk Summary

Option	TOTEX Budget ($) 2019-24	CAPEX Budget ($) 2019-24	OPEX Budget ($) 2019-24	Annual Residual Exposure ($) 2019-24	Annual Risk Change ($) 2019-24
Option 0 – Do Nothing Strategy	$100,000	-----	$100,000	$103M	Increases risk exposure by $66M compared to 2017 levels of $37M
Option 1 – Existing Strategy	$5,500,000	$3,000,000	$2,500,000	$50M	Increases risk exposure by $13M compared to 2017 levels
Option 2 – Reduce Cost Strategy	$5,000,000	$3,000,000	$2,000,000	$48M	Increases risk exposure by $11M compared to 2017 levels
Option 3 – Maintain Risk Strategy	$10,140,000	$8,390,000	$1,750,000	$37M	Maintain risk exposure to 2017 levels of $37M
Option 4 – Reduce Risk Strategy	$16,750,000	$15,000,000	$1,750,000	$25M	Reduce risks by $12M with respect to 2017 levels

Table 11: Cost and Risk Strategy Options Summary

5.2.2 Options Assessment

A scoring matrix approach is used to assess the advantages, disadvantages, risks and benefits of each of the asset management options. Each option is given an overall score, based on the scoring criteria detailed in Table 12.

Criteria	Description and Weighting
Cost	This ranks the relative CAPEX and OPEX costs associated with the options. The weighting reflects the relative importance of this criterion.
Risk – Safety, Environmental, Reliability, Other	The extent to which the option provides mitigation/controls to risks identified. The weighting reflects the relative importance of this criterion.
Strategic Objectives	The extent to which the option meets the requirements of the asset management strategic objectives. The weighting reflects the relative importance of this criterion.
Innovation/Benefits	The extent to which the option provides business benefits including but not limited to information or intelligence to support innovative asset management and network operation. The weighting reflects the relative importance of this criterion.

Table 12: Option Evaluation Scoring Criteria

	Criteria				Option Score
	Cost	Risk	Strategic Objectives	Innovation/ Benefits	
Criteria Weighting	30%	30%	30%	10%	100%
Option 0 – Do Nothing	3	1	1	1	53%
Option-1 – Current Strategy	2	2	2	2	67%
Option 2 – Reduce Cost	3	2	2	2	77%
Option 3 – Maintain Risk	3	2	3	3	90%
Option 4 – Reduce Risk	1	3	3	3	80%

Scoring Key			
0	Fatal flaw	1	Unattractive
2	Acceptable	3	Attractive

Table 13: Scoring Matrix

5.3 Recommended Option

A risk condition based costing approach has been adopted to determine the most optimal recommendation for capital replacement projects and maintenance strategy that will provide the best technical and commercial benefit to Evoenergy in alignment with the AER's strategic objective of reduction in condition monitoring expenses.

This approach is expected to improve the SAIFI/SAIDI figures and improve the STPIS benefits. Based on the evaluation of different scenarios for CAPEX and OPEX in section 5.2, the option that will provide the greatest benefit is given below.

5.3.1 Asset Strategy Recommendation

This section gives the recommendation for the preferred asset management strategy option.

The graph in Figure 8 provides an overall picture of all five risk options.

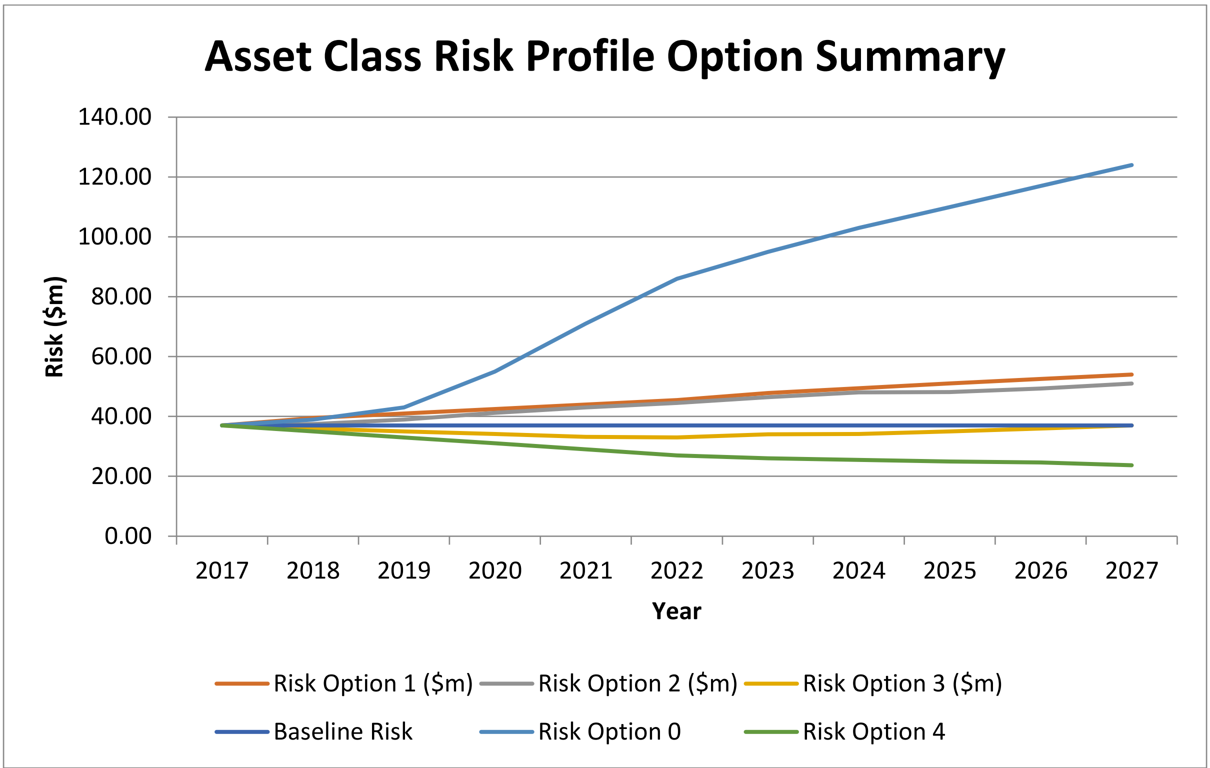

Figure 8: Risk Profile Comparison – Zone Protection Assets

While Option 4 looks attractive, the very large step change in the asset replacement program would be difficult to deliver from a resourcing and coordination perspective.

Based on the risk management approach adopted to deliver a viable secondary zone protection asset management plan, Option 3 – Maintain Risk has been chosen as the most viable strategic approach that would provide the following benefits:

- Cost optimisation of OPEX and CAPEX
- Management of asset profile risk and improved future health condition
- Condition monitoring of primary and secondary assets
- Compliance with the NER and AER’s strategic objectives.

5.3.2 Forecast Asset Condition

Health profile is determined by asset condition and performance history. Condition is determined by the asset's capacity to meet requirements, asset reliability and its level of obsolescence. Obsolescence will be determined by maintenance requirements and availability of support from manufacturers.

The future health profile is the asset health profile at the end of the Regulatory Period, year 2024, under the recommended option to maintain risk exposure. This forecast is based on:

- Initial health profile
- Deterioration due to aging
- Deterioration where condition monitoring identifies specific risks for certain models of equipment
- Allowance made for replacement and refurbishments.

A strategic decision is made at the start of the period on the adequacy of the asset class health, and whether the asset class health should be maintained, improved, or allowed to decline during the period. The maintenance program is adjusted to achieve the required asset class health at the end of the period.

Manufacturer	Model	Quantity (2018)	Current Average Health (2018)	Projected Quantity (2024)	Projected health by end of 2024
Transmission Line Distance Protection Relay		**45**		**45**	
ABB	RELZ100	2	Poor	0	
AREVA	P443211A4N0320J	1	Good	1	Fair
ASEA	RAZFELINEDISTT1	8	Poor	6	Poor
ASEA	RAZOGLINEDISTAN	2	Poor	0	
REYROLLE	HTYPELINEDIST	6	Poor	0	
SIEMENS	7SL2410-3AA5	12	Poor	6	Poor
SEL	SEL411L	7	Excellent	16	Excellent
SCHNEIDER	MICOM P545	7	Excellent	16	Excellent
Translay Feeder Protection Relay		**15**		**15**	
GEC	HO4	15	Fair	15	Poor
Single Phase Transmission Line Protection Relay		**33**		**33**	
GEC		13	Good	13	Fair
GEC	MCGG21(125V)	10	Good	10	Fair
GEC	METI11	3	Good	3	Fair
GEC	MCGG22(125V)	7	Good	7	Fair
Busbar Protection		**64**		**64**	
GEC	FV2	4	Fair	4	Poor
GEC	FAC34	50	Fair	50	Poor
GEC	MFAC	10	Excellent	10	Good
Transformer Protection Relay		**174**		**128**	
REYROLLE	4C21-Dupbias	46	Fair	26	Poor
ASEA	RADSB	33	Fair	18	Poor
GEC	VAJH	65	Fair	40	Poor
EMAIL	2K153	22	Fair	14	Poor
SEL	SEL487E	4	Excellent	15	Excellent
SCHNEIDER	MICOM P687	4	Excellent	15	Excellent
Single Phase Feeder Protection Relay		**262**		**119**	
EMAILELECTRONIC		68	Fair	32	Poor
GEC	MCGG21(125V)	4	Good	4	Fair
GEC	CDG21AMLZ1AF137	46	Fair	40	Poor
GEC	MCSU (125V0.1-9.	90	Fair	40	Poor

Manufacturer	Model	Quantity (2018)	Current Average Health (2018)	Projected Quantity (2024)	Projected health by end of 2024
GEC	MCGG22(32V)	15	Fair	0	
GEC	CAG12/VT11(32V)	1	Fair	0	
GEC	CDG23AF1169E5	4	Fair	0	
GEC	CDG11AF42A	3	Fair	0	
GEC-ALSTOM	MCGG22(125V)	28	Fair	0	
SCHNEIDER	P120	3	Good	3	Fair
Feeder Protection		**302**		**302**	
ABB	ABB-SPAJ140C	84	Poor	0	
NILSEN	NILSTAT	84	Poor	0	
SEL	SEL351A	67	Excellent	67	Good
MICOM	MICOM P145	67	Excellent	67	Good
SEL	SEL351A			84	Excellent
MICOM	MICOM P145			84	Excellent

Table 14: Zone Protection Asset Condition as at 2024

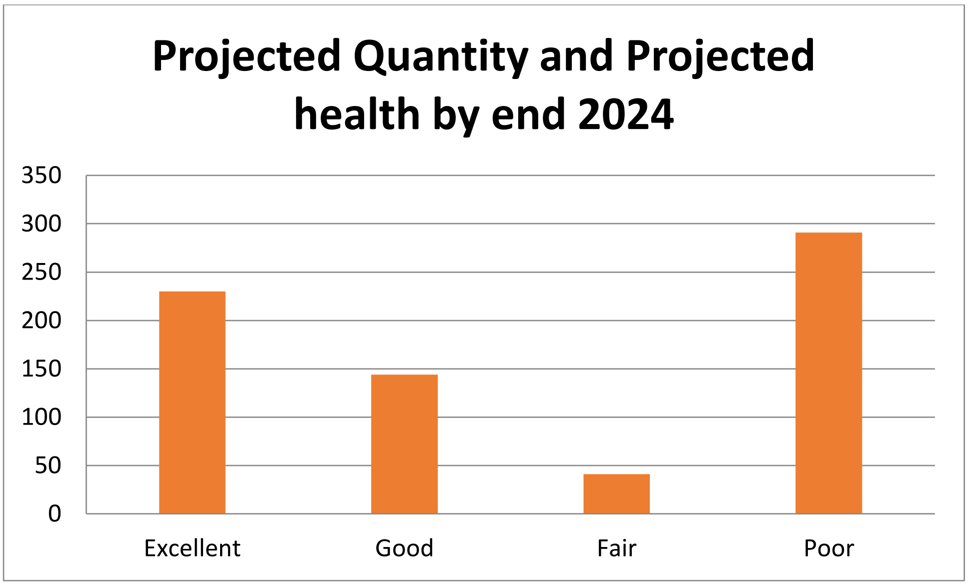

Figure 9: Asset Future Health Profile – Zone Protection Assets

6 Implementation

This section provides implementation details for the recommended asset management strategy option.

6.1 Asset Creation Plan

Assets are added to the network from asset replacement and network expansion plans. Acquisition plans for asset renewal from a protection perspective aligns with Evoenergy's protection strategy of combined protection and substation automation in accordance with best industry practice. Accordingly, modern numerical protections are the preferred replacement option.

Over the next few years, assets related to underfrequency-based graded load shedding shall be installed at all the Evoenergy zone substations.

As a part of NER compliance, all 132kV transmission lines will be augmented with line differential protection functions to align strategically with the ongoing OPGW communication augmentation projects.

6.1.1 Network Augmentation Requirements

6.1.1.1 Under Frequency Load Shedding Scheme

Major power system disturbances on the national grid include the loss of generation and tripping of interconnector ties. Such disturbances cause an imbalance between generation and load consumption leading to a decline in the network frequency from its nominal value. To prevent system collapse during under-frequency events load must be rapidly shed to stabilise and recover the network frequency. Underfrequency load shedding relays are therefore provided to stabilise the network in the event of a grid disturbance.

The NER administered by the AEMC clause S5.1.10 outlines the obligations for Network Service Providers in relation to maintaining power system security and reliability standards. NSPs in consultation with the AEMO under S5.1.10 must ensure that a sufficient amount of load (minimum 60% expected demand) is under the control of automatic under-frequency load shedding (UFLS) relays that in the event of multiple contingency events, the network system frequency does not move outside of the extreme tolerance limits. NSPs must therefore provide, install, operate and maintain facilities for automatic load shedding and conduct periodic testing of the facilities without requiring load to be disconnected. The relay settings are to be determined in consultation between AEMO, TransGrid and the Office of Sustainability appointed as the Jurisdictional System Coordinator for the ACT.

In order for Evoenergy to comply with the NER in relation to power system security this project has been initiated to introduce automatic under-frequency protection into the ACT distribution network.

Evoenergy has previously identified the need to develop and implement a load shedding scheme based on underfrequency protection as outlined in the Electrical Network Augmentation Plan in accordance with the requirements set by AEMO and TransGrid. Suitable underfrequency protections have been procured and are available in stock ready for deployment under this program.

UFLS schemes have been installed at Theodore, Gilmore, Gold Creek and Latham zone substations. Currently, UFLS schemes are being designed and installed at Wanniassa and Woden zone substations as part of 2016/17 program. This augmentation program will continue till 2023/24, whereby all the zone substations will be augmented with underfrequency load shedding scheme.

6.1.1.2 *Transmission Line Protection*

In order that the 132kV network protection meets the NER requirements for fault clearance times, the transmission line protections shall be upgraded under an augmentation program as follows:

- Upgrade protection and install unit line differential protection as OPGW becomes available
- This project would link with the OPGW communication systems augmentation program
- Upgrade sole protection to duplicate protection; this represents a major risk and is not compliant with the NER
- Duplicate circuit breaker failure protection.

An example of transmission line protection assets has been profiled before and after the regulatory period replacements have been effected.

6.2 Asset Maintenance Plan

The objective of this maintenance plan is to economically achieve the longest possible reliable working life of assets. This is done through condition monitoring, preventative and corrective maintenance and has been adapted to Evoenergys assets, operating environment and conditions.

6.2.1 Development

The maintenance plan is designed to achieve the objectives of the asset specific strategy. The following engineering techniques were used to develop the maintenance plan:

- Failure Mode and Effects Analysis (FMEA)
- Condition monitoring
- Historic performance
- Equipment manuals
- Continuous review of asset performance and fine-tuning of maintenance triggers.

Asset Type	Maintenance Task	Maintenance Trigger
Zone 11 kV Protections Static/others	Condition Assessment	4 years
Zone 132 kV Protections static/others	Condition Assessment	4 years
Numerical protections for both 11kV and 132kV	Condition Assessment	4 years sanity check and 8 years full in-situ maintenance

Table 15: Zone Protection Asset Maintenance Interval Summary

6.2.2 Condition Monitoring

6.2.2.1 *Testing*

The condition of protection relays is determined from comprehensive condition assessments by performing testing of protection pick-ups, characteristics and scheme functionality using Doble test plans. The condition assessment includes evaluating set parameters by simulating various abnormal power system conditions and faults.

Assets are tested to ensure the condition is satisfactory, fault pick-up is within calibration and can remain in service and operate reliably and safely. This test also supports the condition based replacement strategy and is performed at the prescribed zone substation maintenance intervals.

6.2.3 Maintenance Strategy

The following sub-sections detail the newly proposed maintenance cycle that seeks alignment with the primary equipment maintenance cycle to optimise outages (some will remain the same as before).

6.2.3.1 Zone Substation 11kV and 132kV Static Relays

The criterion for the maintenance cycle is to reset the primary and secondary maintenance cycle to the same date in order to maintain both of these devices with one outage.

The maintenance cycle of 11kV OCB is 4 years and every 8 years for a major overhaul.

This will prompt us to reset the secondary static protection maintenance cycle to 4 years instead of 3 years.

Therefore even if it were to be a VCB that would be maintained every 8 years, the static protections would be maintained twice in this period and yet aligned to the circuit breaker maintenance cycle.

The only notable exception would be the busbar protection, which should be aligned with the overall zone substation maintenance cycle of four years.

For 132kV network, the circuit breaker, disconnectors and other primary equipment that get maintained in a major overhaul every 8 years on an average, the static protections would be aligned with the four year maintenance cycle.

6.2.3.2 Zone Substation 11kV and 132kV Numerical Protections

Since numerical protection relays are equipped with built-in self-supervision features, they require less maintenance effort compared to static protection relays.

Therefore for both the 11kV and 132kV network in the first 4 years, we are proposing a minor maintenance on their parameters and operations, followed by a comprehensive protection function check after 8 years.

Furthermore, if we are able to keep a record of successful protection operations, the maintenance for such protections could be deferred to the next cycle.

Alternative scenarios have been considered for optimising OPEX and CAPEX costs, reliability improvements and safety.

6.3 Asset Renewal Plan

This asset renewal strategy minimises risk through planned replacement or refurbishment of assets at end of life before catastrophic failure. The condition based replacement strategy uses asset condition to trigger asset replacement or refurbishment and considers the following factors;

- Poor condition from condition assessments and consequently high risk
- Economic obsolescence (economical to replace with alternative product)

- Technological obsolescence (availability of spare parts and support)
- Safety risk (inherent fault in a type of equipment)
- Suitability of ratings.
- Expected 20 year asset life for numerical protection relays and 30 year asset life for static protection relays

The decision to replace or refurbish zone protection assets is assessed on a case by case basis to the whole of life costs, technical feasibility, safety improvements from modern technology and network planning and alignment with the philosophy of combined protection and substation automation in accordance with the best industry practice. We take a strategic approach to asset replacements informed by the condition of the assets and with consideration of opportunities offered through enhanced functionality provided by modern numerical relays.

Evoenergy has identified the need to replace a significant number of problematic relays due to defects and performance, obsolescence and functional deficiencies in a number of critical protection applications on both transmission and distribution networks. These relays are integral to the safe and secure performance of the network. It is a requirement that Evoenergy be in a state of preparedness for either scheduled replacement or replacement arising from premature failure. Evoenergy has already undertaken planned relay replacements programs under the CAPEX program of works. The protections that were either defective or out of date have been proactively replaced at Civic, Gilmore and Bruce. Over a period of the next ten years, it is anticipated that most of the old ageing and defective protections shall be replaced under the CAPEX program.

6.3.1 Key Drivers

The following factors drive the CAPEX programs pertaining to protection assets:

- Replacing faulty assets with poor condition – Generally, faulty units amount to protection relays whose components have either failed or operate with deviation in their parameters. Notably, these assets have a poor condition score, and thereby are candidates for replacements.
- Replacing aged assets – This would amount to replacing relays which are close to reaching the end of life in terms of the stipulated MTBF or its performance including technological obsolescence such as inability to communicate with SCADA.
- Replacing asset with support issues – Either no OEM support or no/limited spares. This problem is typical of either the product having reached the end of its life-cycle or the manufacturer is no longer in business.
- Replacing assets with small populations – Optimise maintenance and assets that are hard to maintain. Rationalisation of the asset base to fewer asset types reduces maintenance requirements, test plans and learning curve of personnel managing the assets.
- Replacing assets that do not meet regulatory requirements – Assets that do not meet regulatory compliance in terms of unit protection scheme or with expedited operating times such as the old static distance protections are increasingly being replaced by modern multifunction protections that can provide unit protections and offer redundancy of protections.
- Replacing assets to meet emerging network requirement – Evoenergy is facing major challenges with the ingress of medium and small solar generations and battery storage devices. This requires a rethink of protection philosophy and application due to the alteration of the network behaviour due to low fault currents and voltage regulation.

- Providing total solution of monitoring and protection – There is an opportunity to replace old protections and SCADA with newer concepts of integrated protection and substation automation. The application of this concept results in a comprehensive secondary systems solution that provides protection, control and condition monitoring of primary and secondary systems. The strategy for protection is a subset of the larger network management strategy, of which monitoring, communication and data acquisition form the cornerstones of a comprehensive network solution. This implies a combined protection and SCADA solution.
- Improve safety and reliability – The protection philosophy is based on the provision of duplicate redundant protection systems operating simultaneously to mitigate failures and ensure availability under all conditions in accordance with the NER. The NER requirements exclude the grandfathering provisions for new assets or assets that are being augmented or replaced.

The methodology for determining criterion for replacements to occur through RIVA has been adequately explained under the section pertaining to asset maintenance strategy.

6.4 Asset Disposal Plan

The assessment of disposal plans for zone protection system assets is based on the following key criteria:

- Obsolescence of technology
- Expected asset life of 20 years (for numerical devices)
- Mean time between failure of components typically 20-30 years for old static relays
- Failures and deviation in performance
- Power system conditions and changes in system configurations.

When determining the time frame for replacement and disposal, it is recommended that the lower of the two figures between MTBF and technology obsolescence be applied.

A planned and phased approach should be adopted towards disposal of protection assets such that:

- All historical and operational data are migrated to the new system
- Operational continuity is ensured.

So far within Evoenergy, relays removed from service are stored as inventory to replace faulty units. This process will continue until an asset class is no longer in service and therefore spares are not required.

6.5 Associated Asset Management Plans

Zone protection assets are aligned to the concept of combined protection and substation automation. In terms of maintenance strategies, they are aligned to primary equipment, be it 132kV circuit breaker or 11kV switchboard. Whilst most of the replacement of protection assets occurs independently, which in some cases extends the mid-life range of the switchgear, an 11kV switchboard replacement almost invariably results in providing the opportunity to replace ageing protection equipment.

6.6 Asset Strategy Optimisation Plan

The aim of the asset optimisation plan is to provide:

- Completion of condition monitoring across all assets
- Online condition analysis from IED protection relays.

By implementing the asset optimisation plan for zone protection assets, the following additional benefits eventuate:

- Reduction of condition monitoring expenditure of secondary protection assets by increasing maintenance frequency and obviated condition monitoring expenditure

- Reduction of primary equipment condition monitoring expenditure due to monitoring of circuit breaker contact wear, close and opening time and determining maintenance interval based on the aggregate of short circuit current interrupted.

7 Program of Work

This section provides the program of work and the resulting operational and capital expenditure forecasts.

The strategic approach to maintenance relies on the optimisation of the maintenance frequency. This approach seeks alignment of maintenance frequency of secondary protection devices with the primary equipment maintenance cycle. Modern numerical protections are provided with in-built self-supervision feature. Therefore, it is proposed that these devices be checked for their functional operation in four years and a complete in-situ maintenance in eight years' time. This approach results in reducing outage costs whilst maintaining or reducing risk of asset failures and optimised condition monitoring. The OPEX budget is therefore expected to reduce from its current value of $500k to $350k, thus constituting a 30% annual reduction.

7.1 Maintenance Program

This section outlines the operational expenditure for preventative maintenance, corrective maintenance and condition monitoring.

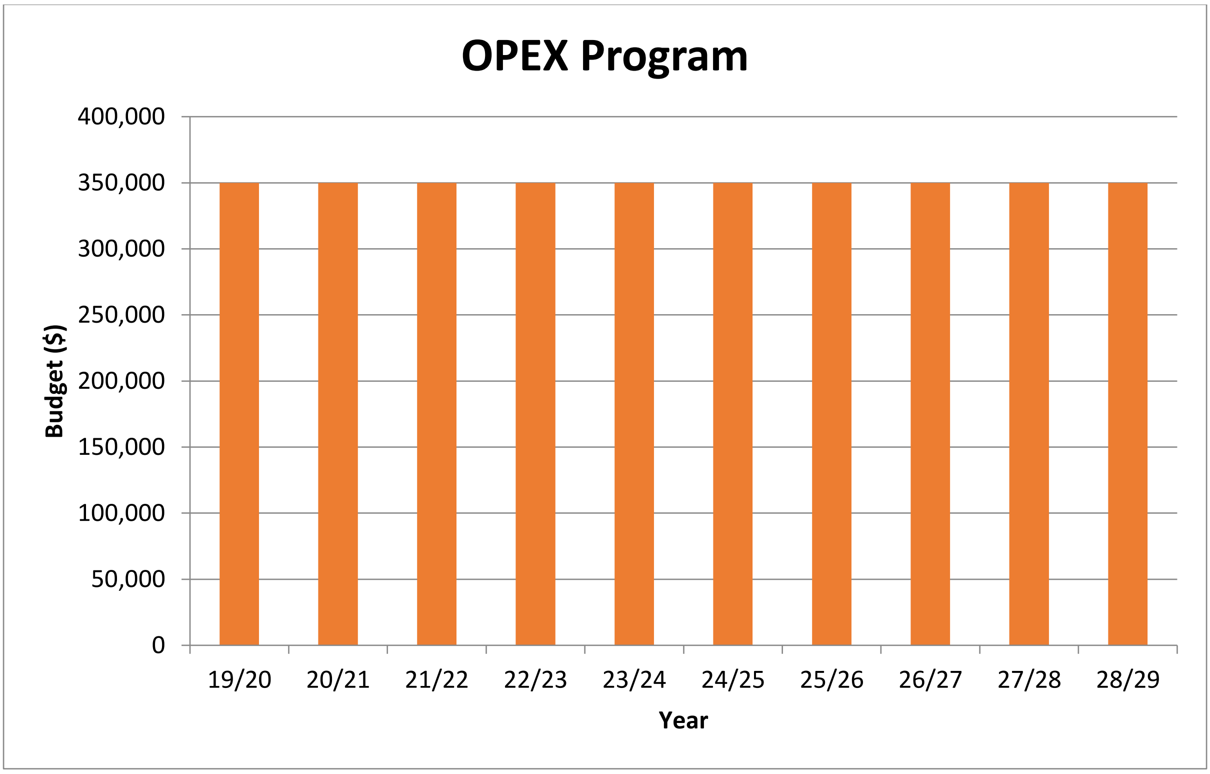

Figure 10: OPEX for Maintenance Program of Zone Protection Assets

Program	Secondary Systems Protection Maintenance and Condition Monitoring
2019-24 Budget	Annual budget for zone protection assets: **$350,000**
Scope	This program includes: Protection planned and unplanned maintenance and condition monitoring.

Project(s) Details	**Protection Maintenance and Condition Monitoring** The following maintenance activities are to be undertaken for zone substation protection asset maintenance on an annual basis: 5 – zone substation 132kV Line protections 7 – zone substation 132/11kV Transformer bays 3 – zone substation Busbar protection schemes 75 – zone substation 11kV feeder bay protection 3 – zone substation battery chargers Note: The above figures are average estimates of assets required to be maintained. The exact quantity and activity mix may vary over the 5 year period.
Risks and Opportunities	Protection condition monitoring and maintenance allows the identification and rectification of issues in protection assets before failure occurs and saves the business any potential loss of revenue and reputational risks due to failure to clear the faults. Protection condition monitoring also assesses the condition of protection assets, optimising the on-going protection replacement program. Results of protection testing can be used to formulate the methodology for the protection replacement program on the basis of the condition monitoring scorecard stored in Cityworks. The scorecard will be formulated on the basis of maintenance works and calibration performed on those assets.
	The strategy for optimised maintenance is based on the revised maintenance strategy of alignment with primary systems assets.

Table 16: Secondary OPEX Zone Protection Maintenance Program

7.2 Capital Program

This section outlines the capital expenditure for asset replacement and refurbishment.

The strategic approach to CAPEX spend in relation to protection replacements is based upon the following rationale that underpins maintaining asset class risk profile at current values:

1. Regulatory compliance

Replacements of protection assets are partly driven by the requirements to comply with the National Electricity Rules. Certain replacements and upgrade are based on providing redundant protections and meeting safety requirements of reduced critical fault clearing time.

The most pressing need from this perspective is the 132kV transmission line protection upgrade to meet fault clearance times as stipulated in the Rules. Line distance protection upgrade with unit line differential protection has been identified in this regulatory period at Wanniassa,Latham and Gilmore zone substations based on compliance with National Electricity Rules.

2. Bottom up consideration of asset condition

Failures, obsolescence and the risk of assets no longer supported result in age and condition based risk to the network. Asset replacements are therefore necessary to mitigate failures and reduce risk profile of the network.

The condition of each make/model family of protection relay has been assessed as shown in table 4. Based on this condition report, the most pressing need is to address the failures and poor condition of SPAJ140C and Nilsen Nilstat overcurrent / earth fault protection.

The SPAJ relays are predominantly used as backup protection at a number of sites such as City East, Telopea, Wanniassa, Woden, Latham and Belconnen zone substations. The prioritisation for this brand of assets can be achieved based on the criticality of the zone substation where it is deployed. Based on the criticality of loads, Woden and City East zone substations would be prioritised ahead of other zone substations.

The Nilsen Nilstats however have been concentrated at Telopea Park and Theodore zone substations. These relays are used at Telopea Park zone substation as both main and backup protection of 42- 11kV circuit breakers. Deepnding on the criticality of the loads, Telopea Park zone substation would be prioritised over Theodore zone substation.

At City East zone substation for few feeders, Nilsen Nilstat and SPAJ 140C have been deployed as main and back-up protections. These feeders present the highest risk of protection failures due to a combination of two assets with poor condition record and failure history. Therefore City East zone substation would be prioritised to mitigate this risk.

3. Prediction of asset failure

It is difficult to predict the next possible location of SPAJ140C overcurrent/earth fault protection failures due to its random nature. The Nilsen Nilstats however are more likely to fail at Telopea Park zone substation where they are concentrated most (42-11 kV Circuit breakers).

4. Top down approach to asset management

Modern numerical protection relays have a life expectancy of 20 years. Evoenergy has currently 14 zone substations and two switching stations, with a further three zone substations planned in the next ten years. Taking into account the number of zone substations (19 in total) and the 20 year life expectancy of modern numerical protection devices, it would be prudent both from financial and delivery perspective to deliver one zone substation protection replacement project every year. The forward cash flow proposed in this asset specific plan is reflective of this approach. For certain zone substations, the protection replacement activity extends the mid-life of the primary switchgear equipment by at least another ten to fifteen years.

The proposed program meets the asset condition / age base replacement needs and is balanced in terms of managing the overall asset base by targeting one ZSS replacement each year.

The top down approach aims to ensure that the program is deliverable over the longer term and that the program is smoothed to avoid peaks and troughs.

5. Program Prioritisation

The prioritisation of protection replacement is based on the following approach:

- The failure history of the protection relay assets.
- The results of maintenance and condition monitoring undertaken on individual assets at each zone substation.
- The condition assessment of each make/model family of protection relay.
- The criticality of each protection relay in terms of connected load and customers, the likelihood and consequence of faults on the network segment and network reliability (STPIS).

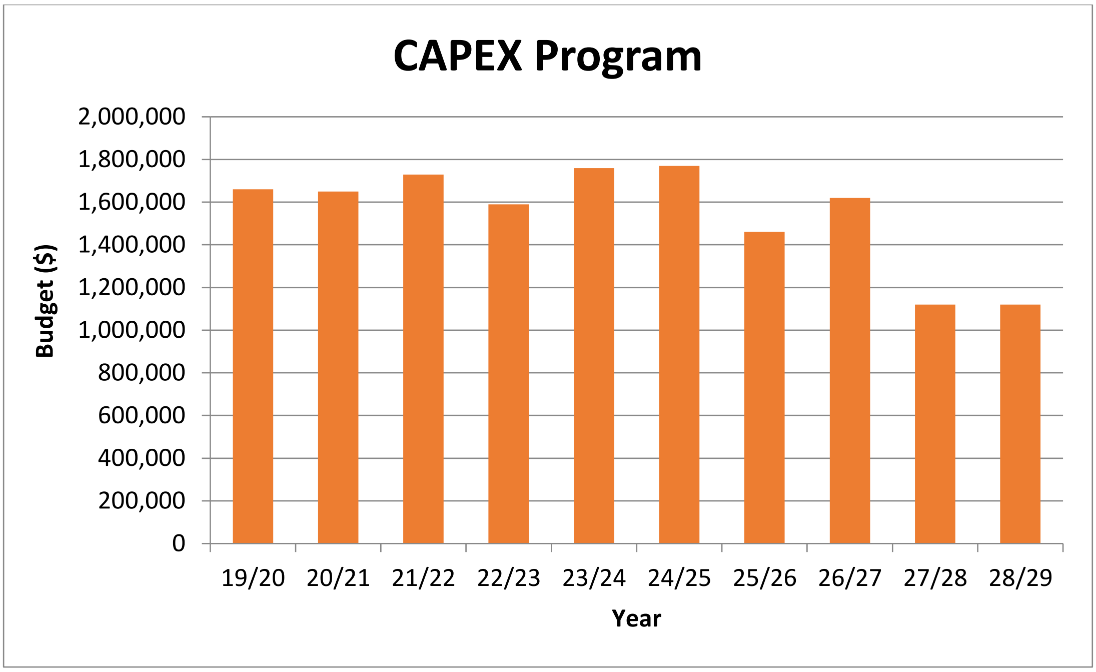

Figure 11: CAPEX Program for Zone Protection Assets

S.No	Project Title	Proposed Budget	Nominated Year
1	City East Zone substation asset renewal program for transformers, Busbars and 11kV feeders	1.92M	2019-2021
2	Wanniassa Zone substation asset renewal program for lines, transformers, Busbars and 11kV feeders	2.08M	2019-2022
3	Woden Zone substation asset renewal program for transformers, Busbars and 11kV feeders	2.08M	2021-2023
4	Fyshwick asset renewal program *Note: The Fyshwick renewal PJR recommends that a second transformer at East Lake ZSS as preferred to Fyshwick SS renewal.	3.0M* Only required if East Lake does not proceed. Not included in budget	2022-2024
5	Telopea Zone substation asset renewal program for transformers and 11kV feeders	2.08M	2022-2025
6	Latham Zone substation asset renewal program for lines, transformers and busbar protection	1.6M	2023-2025
7	Gilmore Zone substation asset renewal program for lines, transformers and Busbars	0.8M	2024-2026
8	Theodore Zone substation asset renewal program for lines, transformers, Busbars and 11kV feeders	1.68M	2027-2029
9	Gold Creek zone transformer and Busbar protection replacement	0.56M	2026-2027
10	Belconnen Zone substation asset renewal program for lines, transformers and Busbar protection and 11kV feeders	2.4M	2026-2028

Table 17: Secondary CAPEX Zone Protection Replacement Program

7.3 Budget Forecast

This section provides a 10 year forecast for the CAPEX & OPEX budgets.

Total Budget	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
CAPEX	**1,660,000**	**1,650,000**	**1,730,000**	**1,590,000**	**1,760,000**	**1,770,000**	**1,460,000**	**1,620,000**	**1,120,000**	**1,120,000**
OPEX	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**	**350,000**
Planned Maintenance (OPEX)	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Unplanned Maintenance (OPEX)	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Condition Monitoring (OPEX)	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000

Table 18: 10 Year Forecast for CAPEX and OPEX Budgets

The replacement projects have been confirmed through an individual Project Justification Report.

Appendix A Maintenance Plan Details

Appendix A provides additional details of the data used in evaluation of the asset management strategy options, including the costing and budget forecasting.

A.1 Maintenance Task Costing

Unit costs for work on this asset class have been estimated in Riva based on historical actual cost data.

A.1.1 Planned Maintenance Tasks

Unit Costs			
Asset Type	**Task**	**Cost Basis**	**Unit Cost**
Battery Chargers (Zones)	Maintain Zone Battery Charger	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Busbar Protection	Maintain Busbar High Impedance Busbar Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Transmission Line Protection	Maintain CVT Transmission Line Monitor	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Transmission Line Protection	Maintain Intertrip Transmission Line Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Transmission Line Protection	Maintain Multifunction Transmission Line Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$2,314
Transmission Line Protection	Maintain Single Phase Transmission Line Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Transmission Line Protection	Maintain Transmission Line Distance Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$2,314
Zone Substation Feeder Protection	Maintain - General Purpose Feeder Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Zone Substation Feeder Protection	Maintain - Multi Phase Feeder Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Zone Substation Feeder Protection	Maintain - Multipurpose Feeder Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Zone Substation Feeder Protection	Maintain - Single Phase Feeder Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Zone Substation Feeder Protection	Maintain - Translay Feeder Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay	$907

		Test Instructions	
Zone Transformer Protection	Maintain Multi Phase Zone Transformer Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Zone Transformer Protection	Maintain Multifunction Zone Transformer Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$1,814
Zone Transformer Protection	Maintain Single Phase Zone Transformer Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Zone Transformer Protection	Maintain Zone Transformer Differential Protection Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907
Zone Transformer Protection	Maintain Zone Transformer Voltage Regulation Relay	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$907

Table 19: Planned Maintenance Task Unit Costs

A.1.2 Condition Monitoring Tasks

Unit Costs			
Asset Type	**Task**	**Cost Basis**	**Unit Cost**
Protection	132 kV Busbar protection maintenance	Inspect, test and service Busbar protection relays	$907
Protection	132/11 kV Transformer protection maintenance	Inspect, test and service transformer protection relays	$6,113
Protection	132kV Line Bay maintenance	Inspect, test and Service line Distance relays	$1,814
Protection	11kV Feeder Bay maintenance	Inspect, test and Service overcurrent relays	$907
Protection	132kV metering supply	Inspect, test and service 132kV metering supply	$903
Protection	Routine weekly inspection	protection relay operational observation	$568
Protection	Standby Generators 415V AC	Inspect and Service 415 V AC Standby Generators	$454

Table 20: Condition Monitoring Task Unit Costs

A.1.3 Reactive Maintenance Tasks

Unit Costs			
Asset Type	**Task**	**Cost Basis**	**Unit Cost**
Battery Chargers (Zones)	Reactive repairs	Test and prove asset integrity in accordance with standard asset procedures and Relay Test Instructions	$454
Protection	Replacement of relay & rewire device.	Purchase of relay, re-design of protection scheme, development of a new RTI, configuration of relay(s), rewire, testing, Protection integration and commissioning	$60,000

Table 21: Reactive Maintenance Task Unit Costs

Appendix B Risk Definitions

Appendix B provides reference information for how the severity of an effect, the probability of failure and the likelihood of detection are defined and ranked for the analysis of risk.

B.1 Severity

Effect	SEVERITY of Effect	Ranking
Catastrophic	Hazardous-without warning Very high severity ranking, potential failure mode affects safety, noncompliance with policy and without warning.	10
Extreme	Hazardous-with warning Very high severity ranking, potential failure mode affects safety, noncompliance with policy with warning.	9
Very High	Item inoperable, with loss of primary function.	8
High	Item operable, but primary function at reduced level of performance.	7
Moderate	Equipment operable, but with some functions inhibited	6
Low	Operable at reduced level of performance.	5
Very Low	Does not conform. Defect obvious.	4
Minor	Defect noticed by routine inspection.	3
Very Minor	Defect noticed by close inspection.	2
None	No effect	1

B.2 Occurrence

PROBABILITY of Failure	Failure Probability	Failure rate Lamda "λ"	Ranking
Very High: Failure is almost inevitable	Very High: Failure is almost inevitable Possible Failure Rate >= 1 every week	0.1429	10
	Very High: Failure is almost inevitable Possible Failure Rate >= 1 every month	0.0333	9
High: Repeated failures	High: Repeated failures Possible Failure Rate >= 1 every 3 months	0.0111	8
	High: Repeated failures Possible Failure Rate >= 1 every 6 months	0.0056	7
Moderate: Occasional failures	Moderate: Occasional failures Possible Failure Rate >= 1 every year	0.0027	6
	Moderate: Occasional failures Possible Failure Rate >= 1 every 3 years	0.0009	5
	Moderate: Occasional failures Possible Failure Rate >= 1 every 5 years	0.0005	4

PROBABILITY of Failure	Failure Probability	Failure rate Lamda "λ"	Ranking
Low: Relatively few failures	Low: Relatively few failures Possible Failure Rate >= 1 every 8 years	0.0003	3
	Low: Relatively few failures Possible Failure Rate >= 1 every 15 years	0.0002	2
Remote: Failure is unlikely	Remote: Failure is unlikely Possible Failure Rate >= 1 every 20 years	0.0001	1

B.3 Detection

Detection	Likelihood of DETECTION	Ranking
Absolute Uncertainty	Control cannot prevent / detect potential cause/mechanism and subsequent failure mode	10
Very Remote	Very remote chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	9
Remote	Remote chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	8
Very Low	Very low chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	7
Low	Low chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	6
Moderate	Moderate chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	5
Moderately High	Moderately High chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	4
High	High chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	3
Very High	Very high chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	2
Almost Certain	Control will prevent / detect potential cause/mechanism and subsequent failure mode	1