Protection and Control Systems

AMS - Electricity Distribution Network

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Disclaimer

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1 Executive Summary

This document is part of the suite of Asset Management Strategies relating to AusNet Services' electricity distribution network. The purpose of this strategy is to outline the inspection, maintenance, replacement and monitoring activities identified for economic life cycle management of protection and control schemes and SACDA remote terminal units in AusNet Services' Victorian electricity distribution network.

AusNet Services' electricity distribution network has approximately 3515 protection rand control relays and 90 remote terminal units (RTUs) located in zone substations. The protection relays consist of both digital technology types, made up of 49% Intelligent Electronic Devices (IEDs) and 2% microprocessor based relay, and analogue technology types, 30% electro-mechanical and 19% electronic types. The RTU consist of a variety of types, with 49% of RTUs installed at zone substations consist of the older obsolete [C.I.C] type.

Overall health of the fleet has been assessed as 49% in the "Very Good" to "Average" health bands (C1 to C3) health and 16% in "Poor" (C4) and 32% in "Very Poor" health (C5) based on a reliability, obsolescence and modernisation capacity assessment.

A fleet criticality based on the consequence of failure has been determined, based on safety and customer unserved energy impact from failure to operate correctly. Using the health and consequence criticality, a quantified risk assessment has been completed to recommend an economically justified replacement program.

Proactive management of protection and control relay and RTU, application, inspection, maintenance, refurbishment and replacement practice is required to ensure that stakeholder expectations of cost, safety, reliability and environmental performance are met. The summary of proposed asset strategies are listed below.

1.1 Asset Strategies

1.1.1 New Assets

- All new and replacement assets will be designed In accordance with the Station Design Manual and current design standards, undertake replacement of complete protection systems (i.e. X, Y, backup and necessary control and monitoring systems) associated with individual items of primary plant/network sections, rather than individual protection schemes/relays
- Replacement activities shall be incorporated within primary plant replacement, station refurbishment or network augmentation activities as far as practicable, in order to maximise operational efficiency and minimise network disruption

1.1.2 Maintenance

- Continue to maintain protection and control assets as per PGI 02-01-04 and the SPP 02-00-01 suite of documents
- Maintain PGI 02-01-04 and the SPP 02-00-01 suite of documents consistent with the outcomes of ongoing Enhanced Data-Driven Asset Management (EDDAM) studies

1.1.3 Spares

- Continue to maintain sufficient spares to ensure ongoing maintainability of in-service devices
- Maintain decommissioned assets in appropriate working condition as spares, as required to ensure the ongoing serviceability of in-service, poor condition/obsolete assets pending retirement

- Continue to consider device obsolescence, as advised by asset manufacturers and suppliers, in preparation of asset replacement strategies

1.1.4 Replacement

Prioritise proactive replacement of:

- High risk 66kV line protection systems incorporating obsolete and/or poor condition static-electronic and first-generation microprocessor-based distance protection relays (PQ741 and RAZOA-type devices)
- High risk transformer and 66kV bus protection systems incorporating obsolete and/or poor condition electromechanical, static-electronic and first-generation micro-processor based transformer protection relays (KBCH120, D21SE2, D21SE3, DUOBIAS, D21, D202-type devices) and electromechanical and static electronic high-impedance bus protection relays (CAG34, RADHA and RAKZB-type devices)
- High risk 22kV bus, back-up earth fault (BUEF) and master earth fault (MEF) protection systems incorporating obsolete and/or poor condition electromechanical and static-electronic high-impedance bus protection relays (RADHA, 2V73, GROUP, 2V47, SPAJ and RXZK-type devices), electronic bus distance protection relays (DIST-2987-type devices), electromechanical, static electronic and early generation digital BUEF protection relays (DCD, ARGUS C, GROUP and CMUR-type devices) and electromechanical and static-electronic based MEF protection relays (GROUP and ARGUS-type devices).
- 22kV feeder protection schemes incorporating non-compliant and obsolete [C.I.C] relays
- Obsolete, high risk AVE-type voltage regulation relays
- Restricted capability voltage regulation control systems at zone substations affected by significant load growth, and/or as required to accommodate ongoing penetration of low voltage distributed generation
- Obsolete and unreliable [C.I.C] and [C.I.C]-type remote terminal units

1.1.5 Research and Development

- Evaluate process bus applications for use at 22kV
- Continue to refine 22kV earth fault management strategy in response to evolving technologies
- Investigate opportunities and strategies for integrating non-conventional instrument transformers
- Research and develop 3 and 4G solutions for protection signalling (including backup intertrip) applications to address increasing penetration of distributed generation
- Investigate ways to improve primary asset monitoring and maintenance using existing secondary infrastructure

2 Introduction

2.1 Purpose

The purpose of this document is to outline the inspection, maintenance, replacement and monitoring activities identified for economic life cycle management of protection and control assets. This document is intended to be used to inform asset management decisions and communicate the basis for activities.

In addition, this document forms part of our Asset Management System for compliance with relevant standards and regulatory requirements. It is intended to demonstrate responsible asset management practices by outlining economically justified outcomes.

2.2 Scope

The assets covered by this strategy include:

- Protection and Control relays, as employed within network protection and control schemes located within zone substations across the (regulated) distribution network
- Peripheral equipment, including trip relays and timers, isolating/test links and secondary AC and DC wiring circuits that work in conjunction with the protection and control relays to actuate protection and control functions
- Relays and similar devices used in station voltage regulation schemes
- Station remote terminal units (RTUs) and all associated equipment including SCADA HMIs

The following assets are not covered by this strategy:

- Station DC systems and associated monitoring and control equipment (including chargers and alarms) – refer AMS 20-80
- Distributed protection devices, such as ACRs, sectionalisers and fuse savers, that are located outside of the zone substation boundaries – refer AMS 20-60
- Communications infrastructure, such as multiplexors and physical carriers, used for protection signalling (protection and communications boundaries of responsibilities assumed to be located at Comms ITC) – refer AMS 20-81
- Power Quality Meters and Revenue Meters – refer AMS 20-15

2.3 Asset Management Objectives

As stated in *AMS 01-01 Asset Management System Overview*, the high-level asset management objectives are:

- Comply with legal and contractual obligations;
- Maintain safety;
- Be future ready;
- Maintain network performance at the lowest sustainable cost; and
- Meet customer needs.

As stated in *AMS 20-01 Electricity Distribution Network Asset Management Strategy*, the electricity distribution network objectives are:

- Improve efficiency of network investments;
- Maintain long-term network reliability;
- Implement REFCL's within prescribed timeframes;
- Reduce risks in highest bushfire risk areas;
- Achieve top quartile operational efficiency; and
- Prepare for changing network usage.

3 Asset Description

3.1 Asset Function

Protection and control systems are used throughout the AusNet Services electricity distribution network to:

- Detect fault conditions and, by operating the appropriate circuit breakers, de-energise the faulted portion of the network in order to minimise the risk to human life, minimise property and equipment damage, and maintain reliability and quality of supply to customers;
- Monitor and maintain operating voltages within the limits of the Distribution Code;
- Provide specialised control functions, including anti-islanding and runback control for generator connections
- Facilitate network switching via SCADA;
- Provide instrumentation capabilities including measurement of voltage, current and power, as well as plant operating temperatures and environmental conditions to facilitate network operations and control

Protection and control relays form the basis of schemes and systems used to provide protection and control functions for the primary electrical network. Protection and control relays are installed within zone substations and, in conjunction with specialised peripheral circuits, are combined in schemes intended to provide electrical protection and control of a defined primary asset or network section. Each scheme is specifically designed to accommodate the unique characteristics of the associated primary plant/network element (i.e. the “application”). Two or more independent protection and/or control schemes always operate in parallel (i.e. as a “protection system”) for each primary asset or network section in order to maintain a very high level of protection system reliability.

Remote Terminal Units (RTUs) provide SCADA services at zone substations by serving as an interface between the station protection and control schemes and the SCADA system. The SCADA system gathers station information, including instrumentation data (volts, amps, frequency, watts, vars, operating temperatures, conductor strain etc), circuit breaker and plant status information and alarms, and interprets and displays that information in a useful format to local and remote operations personnel.

Each station RTU plays an essential role in the operation of distributed feeder automation (DFA) systems by providing the necessary plant status information and logical processes necessary for coordinated operation of station circuit breakers and distributed automatic circuit reclosers (ACRs) and sectionalisers (refer AMS 20-60).

3.2 Asset Population

Protection and control relays are reported in the “FIELD DEVICES” RIN category (total 5859 assets, 2017 RIN). Zone substation protection and control system assets account for 60% (approximately) of the listed assets. Remote Terminal Units account for 2% of listed zone substation protection and control system assets (almost 90 units).

For asset management purposes, protection and control relays are classified according to their technology type. There are four (4) different technology types: Electro-mechanical, Electronic, (First Generation) micro-processor and intelligent electronic devices (IEDs). Electromechanical relays represent the oldest relay technology, whilst IEDs are the most modern. All new relays installed on the network are IEDs. Alternative technology relays are not used for new or replacement schemes, and the proportion of these relays in service will continue to decrease over the next 10 years, while the number of in-service IEDs increases. As IEDs are generally able to complete the functions of multiple single-function electromechanical, electronic or microprocessor-based relays, the overall population of relays may decrease as older protection and control schemes are replaced with IED-based schemes.

Figures 1, 2 and 3 provide an overview of the relative proportions of relays of each type currently in service across AusNet Services' electricity distribution network, their time in service (age) and their applications.

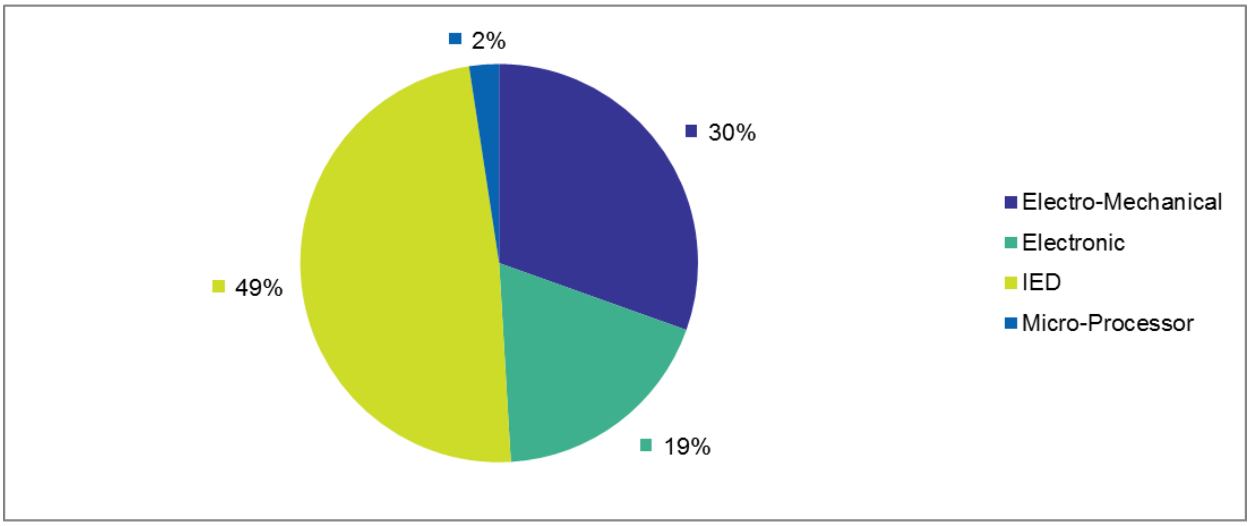

Figure 1: In-service Relays by Type

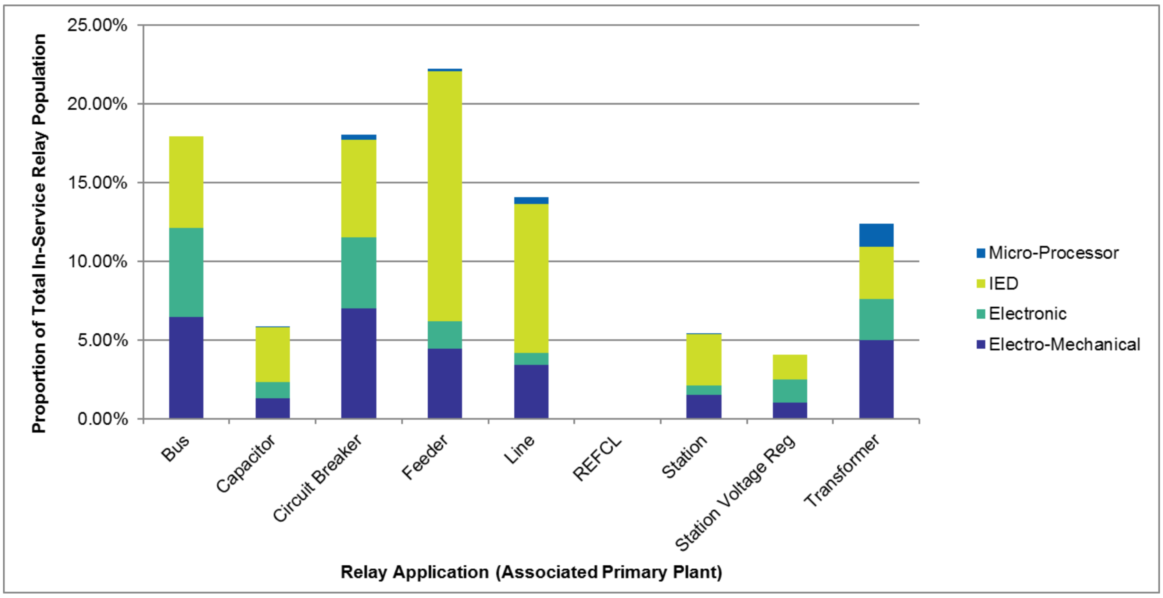

Figure 2: Application Distribution of In-Service Relays by Type

The number of relays (IEDs) employed in REFCL applications will increase significantly over the next 5 years as REFCL technologies are installed at 22 zone substations across the distribution network. In accordance with the "GFN Protection and Control policy" (REF 30-08) and "Earth Fault Protection Strategy for Zone Substations Supplying the 22kV Network" (PPD 01-07), the REFCL program will necessitate upgrade of various station protection schemes, including master and back up earth fault protections, that will contribute to a significant change in population technology profiles over the next decade.

Bulk station voltage regulation (VRR) scheme replacements, necessitated by load growth and the increasing penetration of low voltage distributed generation will, as described in AMS 20-15 (Quality of Supply network strategy), also markedly change the technology profile in this area over the next 5 to 10 years.

3.2.1 Electro-mechanical relays

Electromechanical relays are single function relays with mechanical measurement registers, rotating disc mechanisms, mechanical bearings and spring-based energy storage. Electromechanical relays do not have function supervision capabilities.

30% of the total population of protection and control schemes in service are based on electromechanical relays, which have an average age of 28 years.

Electromechanical relays are used across most protection and control applications, as indicated in Figure 4, but in particular bus protection (21% of the total population of electromechanical relays), circuit breaker failure protection (23%) and transformer protection (17%). Those indicated to be employed on lines and feeders (total 25%) are generally overcurrent protection relays deployed for protection of 66kV lines supplying coal mines in the Latrobe Valley, or voltage relays used to provide neutral displacement detection on 66kV lines, pending upgrade of primary line protection schemes from distance to digital differential protection as appropriate communication facilities become available. Electromechanical relays are no longer employed as primary line or feeder protection relays elsewhere on the network.

The number of electromechanical relays employed across all applications will continue to decrease over the next 10 years.

3.2.2 Electronic relays

Electronic relays are single-function relays that use discrete electronic components such as transistors and simple integrated circuits to complete logical operations. Electronic relays employ discrete capacitors for analogue current and voltage measurement. Some electronic relays have basic functional supervision capability.

Electronic relays represent 19% of the total relay population, and have an average age of 16 years.

Electronic relays are used across a number of protection and control applications, as indicated in Figure 4, but in particular for bus protection (31% of total population of electronic relays), circuit breaker failure protection (24%) and transformer protection (14%).

The number of electronic relays employed across all applications will continue to decrease over the next 10 years.

3.2.3 (First Generation) Microprocessor- based relays

Microprocessor relays are usually single function devices, in which analogue measurements are carried out by microprocessor calculation. Inherently, microprocessor relays have functional supervision capability and will alarm under predefined failure conditions.

Microprocessor-based relays represent 2% of the total relay population, and have been in service for 18 years on average.

Microprocessor-based relays are used across a number of protection and control applications, as indicated in Figure 4, but in particular for transformer protection (60% of the total population of microprocessor relays). This application profile reflects bulk transformer protection replacement projects that were undertaken during the early 2000's across various rural and suburban zone substations.

The number of microprocessor-based relays employed across all applications will continue to decrease over the next 10 years.

3.2.4 Intelligent Electronic Devices (IEDs)

Intelligent Electronic Devices (IEDs), also referred to as digital relays, are multi-function devices with sophisticated programming and configuration capabilities. IEDs undertake protection functions, as well as control functions via a direct SCADA (Supervisory Control and Data Acquisition) interface, and are inherently supervised.

IEDs represent 49% of the total relay population with an average age of 7 years.

IEDs are used across most protection and control applications, as indicated in Figure 4, but in particular feeder and line protections (52% of total population of IEDs). This application profile reflects bulk line/feeder augmentation and protection upgrade projects that have been undertaken within the last decade.

The number of IED-type relays employed across all applications will continue to increase significantly over the next 10 years, as IED-based protection schemes replace protection schemes using alternative technology devices.

3.2.5 Remote Terminal Units (RTUs)

There are five (5) models of remote terminal units (RTUs) currently in service on the AusNet Services distribution network. Figure 4 provides an overview of the population distribution.

C.I.C

The [C.I.C] the oldest RTU types employed in the AusNet Services distribution network. There are only 2 [C.I.C]RTUs remaining in service. Both are located at non-critical or customer sites that are anticipated to be decommissioned within the next 10 years.

[C.I.C] and [C.I.C] RTUs are the next oldest RTU type currently in service. SCADA services to 50% of distribution zone substations are currently supplied via RTUs of this type. At least half of these units will be replaced by 2020, with the remaining units planned for replacement within the following five (5) years, as part of an ongoing[C.I.C] replacement program.

The SCD5200 RTU is a relatively new product which was introduced to the market about 15 years ago. AusNet Services commenced installation of these RTUs about 10 years ago, in place of the already obsolete [C.I.C]. 46% distribution zone substations are connected to SCADA via RTUs of this type.

The [C.I.C] is the latest specification unit deployed within the distribution network. All pending RTU upgrades will involve replacement of the existing unit with a unit of this type. SMP RTUs currently service only 3% of SCADA-connected zone substations, however this number will increase significantly over the next 10 years as the current in-service population of [C.I.C] units are replaced.

3.3 Asset Age Profile

Figure 4 below provide an overview of the relays of each type currently in service across AusNet Services' electricity distribution network and their installed date (age).

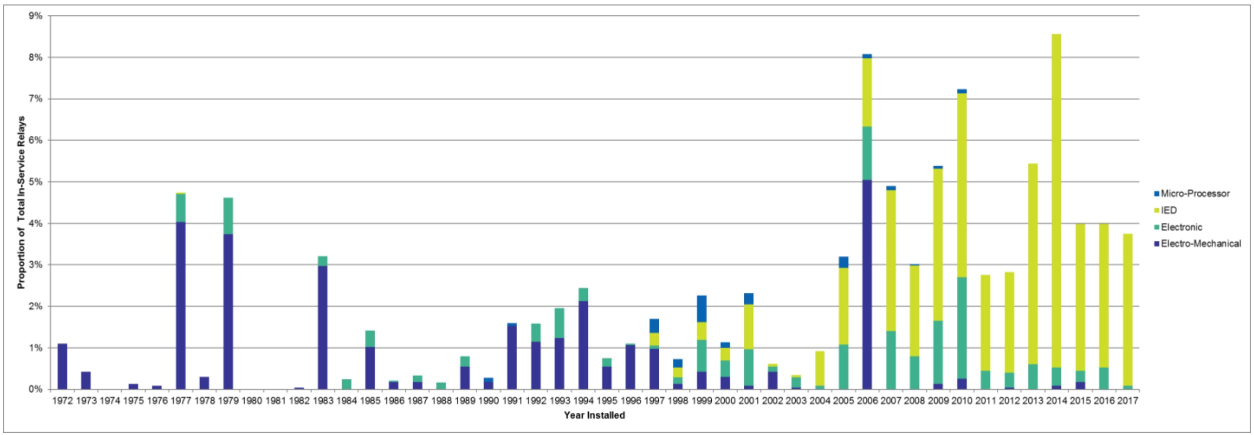

Figure 3: Age Profile of In-Service Relays by Type

3.4 Asset Health

Protection and control asset health is determined via application of a formal health assessment framework. An asset assigned a health rating of C1 is considered to be in "Very Good" or "as new" condition. An asset assigned a health rating of C5 is considered to be in "Very Poor" condition.

Figures 5 and 6 provide an overview of the condition of protection and control relays currently in service across the AusNet Services electricity distribution network.

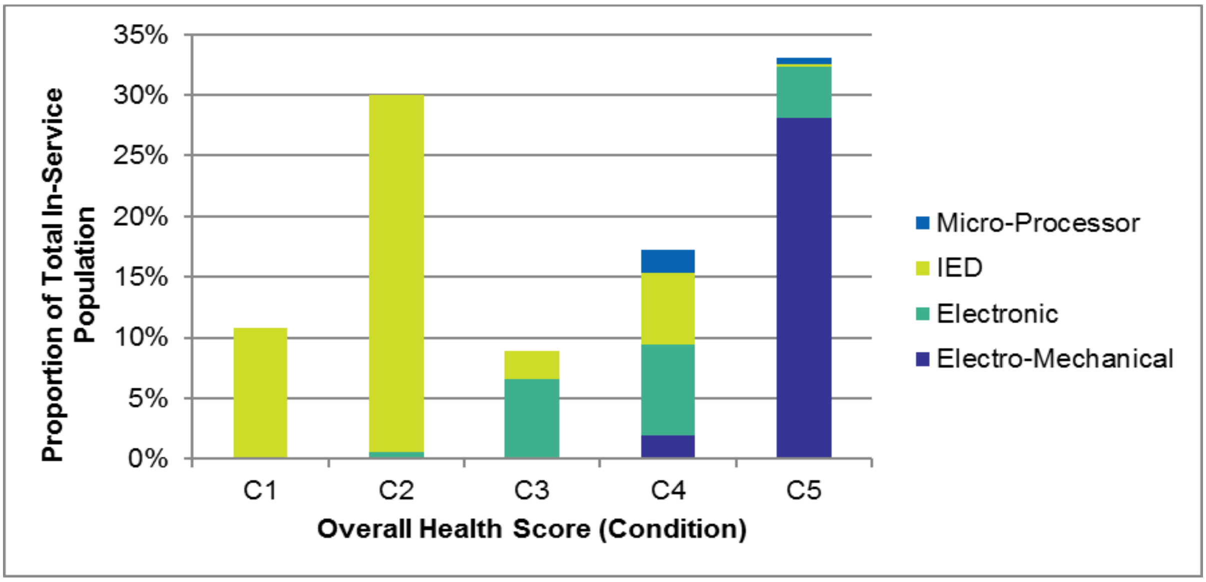

Figure 4: Relay Health Overview by Relay Type

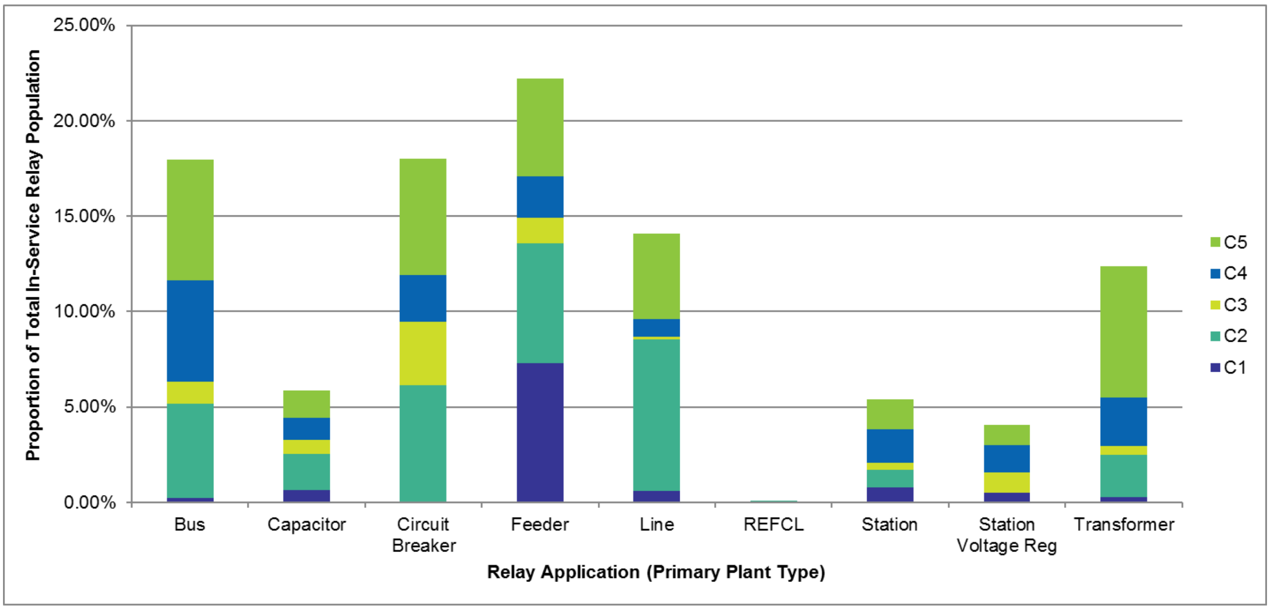

Figure 5: Application Distribution by Relay Condition

3.4.1 Electromechanical Relays

Due to their extended duty, limited capability and function, electromechanical relays are generally considered to be in condition C4 or C5 as indicated in Figure 7.

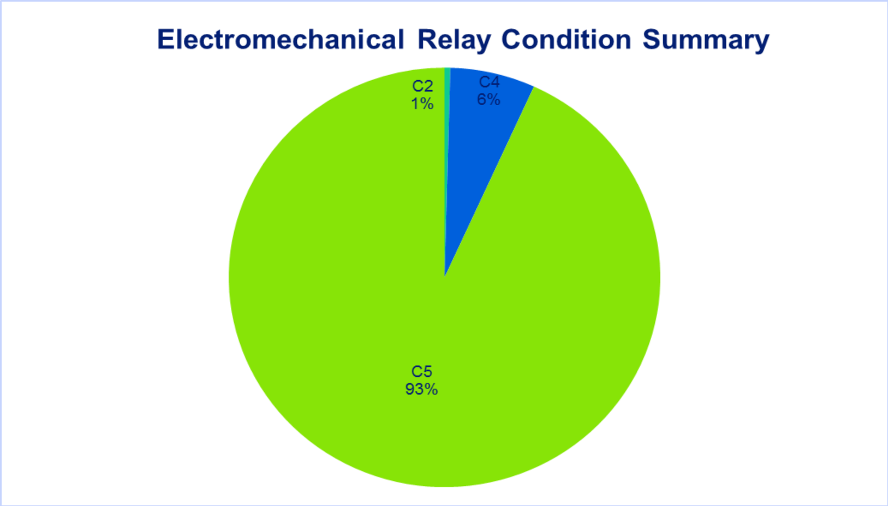

Figure 6: Asset Condition Summary - In-service Electromechanical Relays

Electromechanical relays have bearings that wear and contacts that both erode and corrode over time. Magnetic elements lose their magnetism over time and require frequent adjustment to bring them to the correct calibration, although the capability for adjustment decreases as the asset ages. Many of the more failure-prone relays have been progressively replaced under previous replacement programs. However, there are limited populations of D21SE2, D21SE3 and DUOBIAS-type transformer protection relays remaining in service. These relays are associated with high risk upon failure due to transformer capital value and network criticality. They are more prone to hidden failure due to no self-supervision.

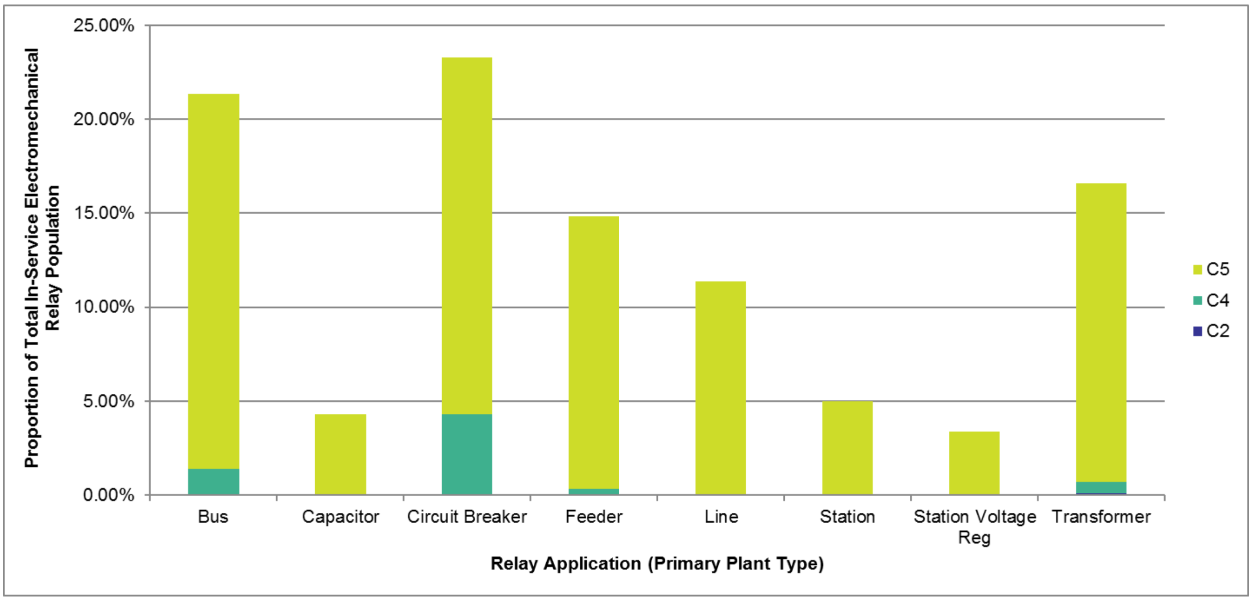

Figure 7: Application Distribution by Condition - Electromechanical Relays

There are also a number of GROUP-type relays employed in back-up and master earth fault (BUEF and MEF) applications. These schemes are considered high risk due to the high customer impact of failure. In recent years, numerous incidences of hidden failure of MEF relays has led to unavailability of the feeder protection, resulting 22kV station black (loss of supply to all station customers) due to BUEF operation when a feeder fault occurs. The BUEF protection has no redundancy when the feeder protection is unavailable.

The majority of remaining electromechanical devices, as indicated in Figure 8, are CAG- or RADHA-type devices (condition C4 and C5, respectively) used for CB failure detection and high impedance bus protection. These are simple relays that are generally considered quite reliable however they do eventually succumb to insulation failure in coils and contact stacks that are continually impressed with the station 120VDC supply voltage. This is long term failure mode that starts to manifest in those assets that have been a long time in service.

Schemes utilising electromechanical relays generally have multiple peripheral components including auxiliary, interposing and trip relays and discrete resistors, each of which is subject to failure modes with the potential to directly impact system reliability. Protection and control schemes using electromechanical relays are also more likely to be associated with grouped (non-discrete) alarm and indication circuits that delay fault finding, diagnosis and repair capabilities.

3.4.2 Electronic Relays

Electronic relays are generally assigned condition scores ranging between C3 and C5, as indicated in Figure 9, depending on their capabilities, the availability of spares and degree of manufacturer support.

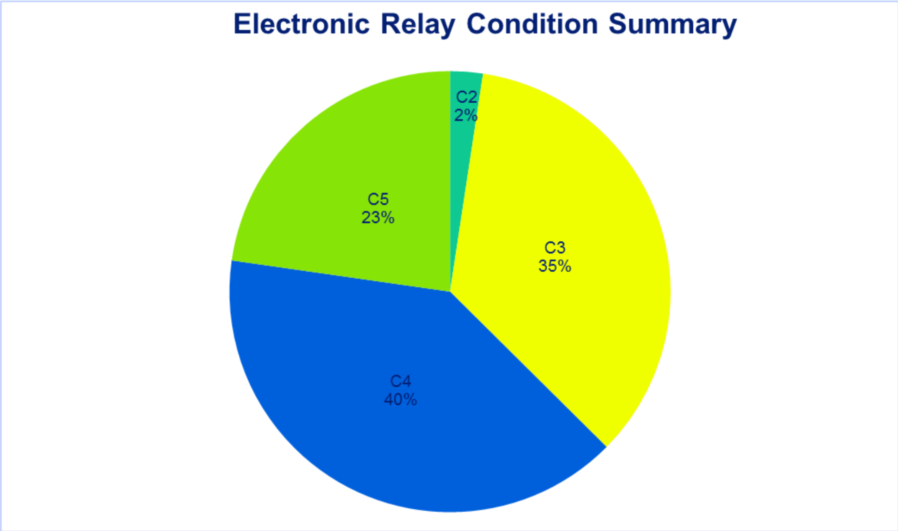

Figure 8: Condition Summary - In-Service Electronic Relays

Electronic relays have components such as electrolytic capacitors and transistors with a mean time to failure comparable to the expected service life of the asset. Most electronic relays use a DC-DC converter as a power supply for the electronic circuits and these present a common source of potential failure due to continuous exposure to the station 120VDC supply. Electronic relays have limited supervision - usually only a power supply fail alarm. Component failures that prevent a relay operation will be unknown until scheduled maintenance is performed, or the protection system is required to operate due to a network fault. Failure is random and unpredictable in comparison to electromechanical relays.

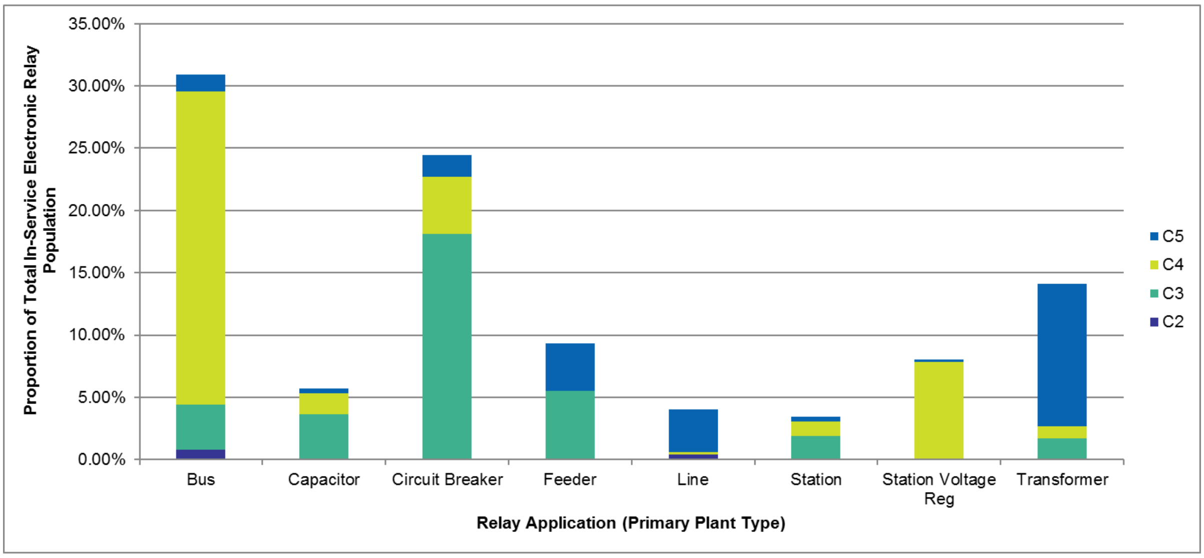

Figure 9: Application Distribution - In-Service Electronic Relays by Condition

As indicated in Figure 10, a high proportion of C5-rated electronic relays are deployed within transformer, line and feeder protection applications.

RAZOA and RAKZB relays are C5 condition electronic relays used for line and bus distance protection applications. All devices of this type currently in service have been in service for between 22 and 35 years. Routine testing of these devices has, in a number of cases, found some calibration errors that suggest deterioration of internal components.

D21 and D202-type relays are used for transformer protection. These devices have generally been in service for over 25 years. Inherent restraint circuit design renders these relays prone to inrush tripping on transformer energisation, which may cause extended customer outages upon return to service or on line reclose when installed on transformers with a direct connection to 66kV lines.

3.4.3 Microprocessor-based Relays

Microprocessor-based relays are assigned condition scores C4 or C5 as shown in Figure 11, depending on their capabilities, the availability of spares and degree of manufacturer support.

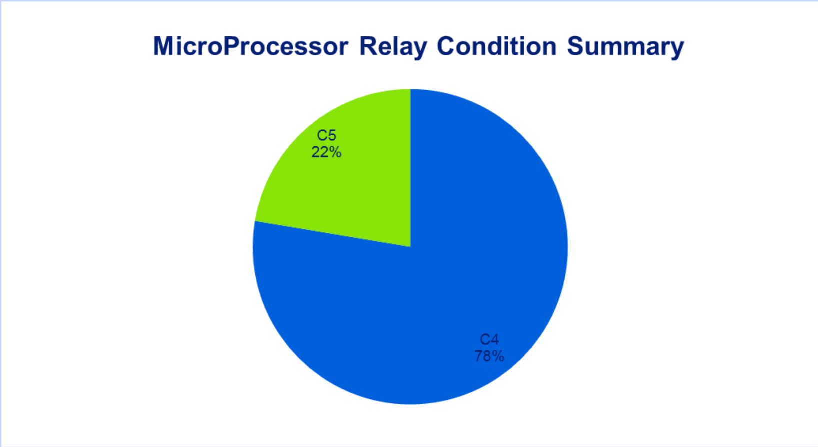

Figure 10: Condition Summary - In-Service Microprocessor Relays

First-generation microprocessor-based relays may be considered in the same light as one would now consider a 1980s PC. Obsolescence through technological development has rendered many devices unsupported by their manufacturers and not able to communicate with modern PCs, which makes them difficult to operate. They have very limited capabilities in comparison to their modern counterparts and do not provide the functionality expected in modern substation protection and control design.

Managing spares for microprocessor-based relays is a major issue. Relays of one type may have multiple variations in software and firmware, posing compatibility problems with relay setting and configurability. This causes serious delays and complications for design and field maintenance, and necessitates keeping of increased number of spares to maintain in service. Spares are generally no longer available for purchase, and the availability of legacy, salvageable devices decreases over time.

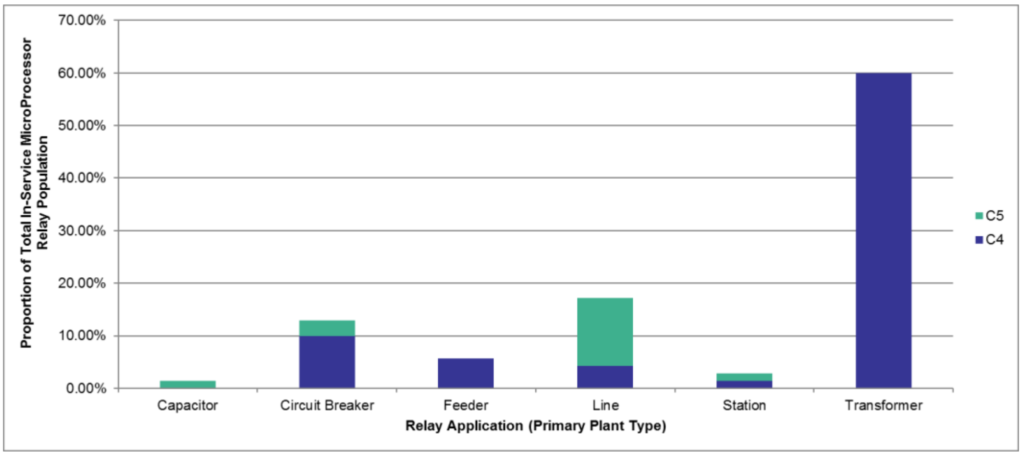

Figure 11: Application Distribution by Condition - In-Service Microprocessor-based relays

As indicated in Figure 12, a high proportion of C5-rated microprocessor relays are used for line protection applications. These are PQ741 and MDT-A2-type relays. All in-service MDT-A2 relays are scheduled to be replaced coincident with completion of REFCL installation works by 2021. The PQ741 devices have been prioritised for replacement within the next 5 years.

The majority of microprocessor relays are deployed in transformer protection and control applications. Although these devices are all considered to be in condition C4, failure of these assets is associated with increased customer impact and primary asset risk. In particular, there are increasing concerns regarding the serviceability of KBCH120-type relays after an incident at Eltham zone substation in August 2018. The highest risk assets have been recommended for replacement within 5 years for this reason. This will also result in availability of retired units as spares for the remaining fleet.

3.4.4 Intelligent Electronic Devices

IEDs offered by different manufacturers vary in functionality and capability. As shown in Figure 13, the majority of IEDs fall into the C2 category, because they are in good operating condition, are supported by their manufacturers and satisfy the bulk of the modernisation criteria applied for condition assessment. Only a limited number of IEDs currently in service support the IEC61850 communications and control standard, which excludes the majority of the population from the C1 condition rating. Some of the older members of the fleet are starting to succumb to obsolescence effects, resulting in assignment of a “Poor” (C4) or “Very Poor” (C5) condition score.

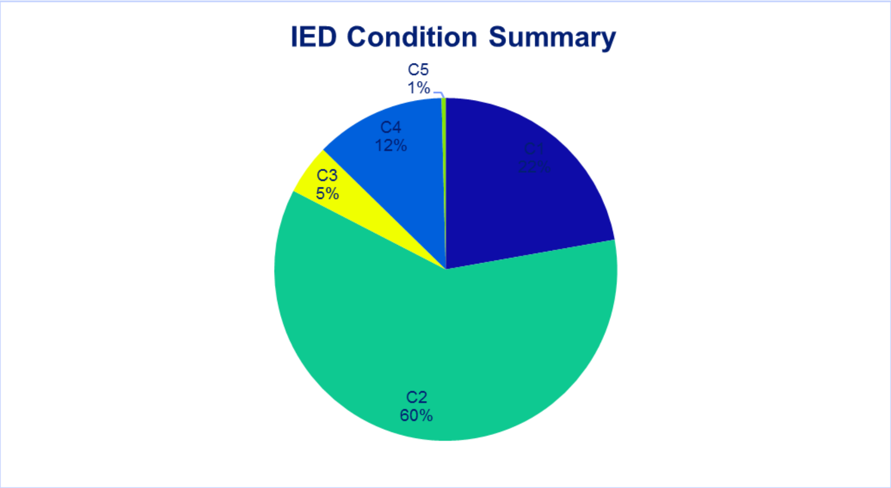

Figure 12: Condition Summary - In Service IEDs

The majority of IEDs in the AusNet Services distribution network are directly connected to the station RTU and may be controlled either remotely (from a central control facility) or via a local station HMI. The requirement for hard wiring of alarm and control circuits is minimal compared to other relay technologies, which offers improvement in alarm diversity and specificity.

IEDs are relatively low cost and allow considerable savings in wiring costs. As well as integrating multiple functions within one device, IEDs are inherently self-monitoring and include event and disturbance recording with remote access capability for network event analysis. They generally offer multiple setting groups with the capability for remote-controlled change between them, which provides operational flexibility for the network and minimises the number of outages required to facilitate network re- configuration. Digital protection functions integrated within IEDs have better setting capability and are generally faster and more accurate.

Obsolescence is becoming an issue with some of the older devices. Because of obsolescence, the service life of an IED is not expected to exceed 15 years, with obsolescence starting to become an issue in some cases within 5 years of installation. Manufacturers generally offer support for these devices within 10 years of purchase, but beyond that time serviceability is dependent upon internal spare management, which becomes increasingly difficult as the service age of the asset increases. As with microprocessor-based devices, increasing degrees of obsolescence are associated with serious delays in design and repair in case of failure.

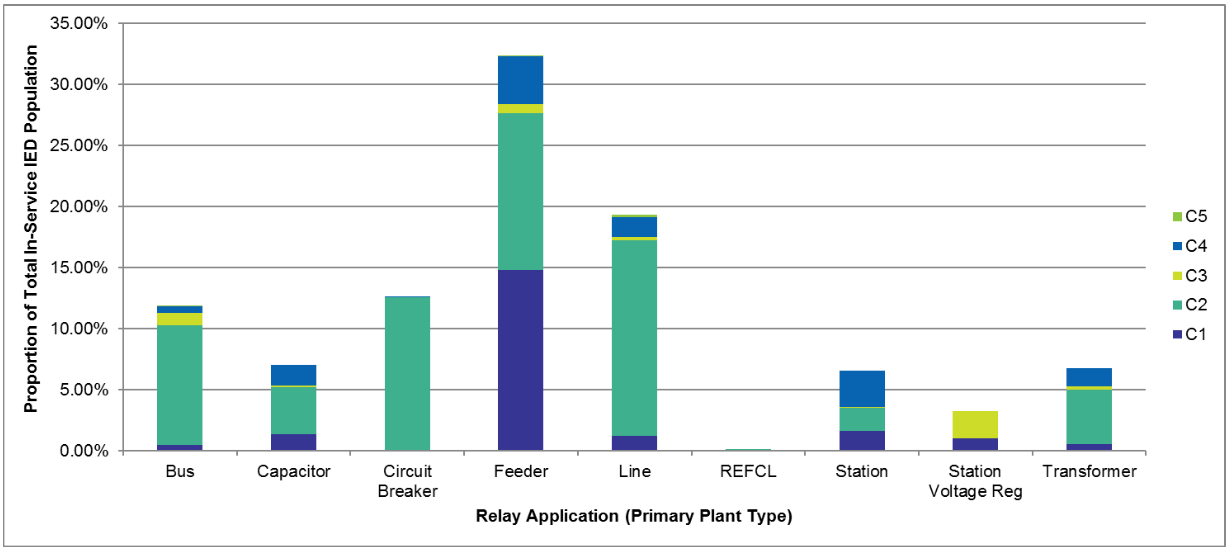

Figure 13: Application Distribution by Condition - In-Service IEDs

One model of IED, the SR760, is not capable of providing feeder protection operation necessary for compliance with ESVs bushfire mitigation directions. All relays of this type are thus considered to be in condition C5. Most of these devices have been replaced under previous bushfire mitigation efforts. There are a handful of devices that were previously considered exempt from bushfire requirements due to not been installed on high bushfire risk feeders. With increase in demand and expectation of network operations and the re-classification of geographic bushfire risk areas, the non-compliance of these assets must now be addressed.

3.4.5 RTUs

Figure 15 provides an overview of RTU conditions across the distribution network.

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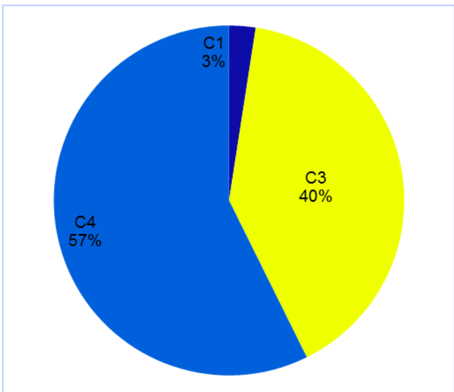

Figure 14: Condition of In-Service RTU's

Due to their limited capabilities and functions, the [C.I.C] RTU is considered to be in condition C4. It is no longer produced nor supported by the manufacturer. It cannot provide communication capabilities to IEDs. The [C.I.C] does have the ability for hardwired expansion, but only to a limited extent. The power supply used by [C.I.C] -type RTUs has a high failure frequency which leads to invisibility of station operational status due to a single point of failure.

Due to their age, limited capabilities and functions, the [C.I.C] and [C.I.C] RTUs are considered to be in condition C4. These units are obsolete, and only a very limited number of spares are available for use in case of failure. The in-service units are rapidly approaching full capacity and cannot be expanded to meet the growing demands of "smart" station equipment. As a result, these units are increasingly subject to system "lock-up" and reset. A lack of inherent redundancy means stations employing [C.I.C] RTUs are subject to an increased level of risk due to:

- An increased probability of component failure, resulting in outage of the entire unit, which in turn prevents operation of the DFA system and requires that the station be manned until repairs can be completed.
- Standard use of "grouped" alarms, whereby critical station equipment alarms are combined into a single alarm point. The consolidated alarm is a single point of possible failure affecting multiple station assets – failure of the alarm to operate when required prevents diagnosis of abnormal asset conditions and/or behaviours prior to asset failure. When the alarm is asserted, a lon6ger response time is incurred when the alarm source is not clear.

[C.I.C]-type RTUs provide some communication capabilities, however they can only interface with IEDs via copper wires using DNP3.0 or MODBUS communications protocols. They do not support other communication protocols, which restricts choice of compatible IEDs in case of asset renewal.

Due to their availability and wide range of communication capabilities, SCD5200 RTUs are considered to be in condition C2. The SCD5200 RTU provides all communication protocols currently used by the business, and the option of optical fibre interface. However, it is not IED61850 compliant, which excludes the SCD5200 from being considered a C1 condition asset.

As the most modern specification RTU, all [C.I.C] terminal units are considered to be in condition C1. In addition to maintaining the capabilities of earlier specification units, these units:

- are IEC61850 compliant (both MMS and GOOSE);
- are IEC61131 compliant (programmable logic control capability);
- are NERC CIP security compliant;
- are IEEE 1588 compliant (Precision Time Protocol);
- provide fully redundant communication to all IEDs;
- provide both fibre and copper interfaces to IEDs;
- are in active production and fully supported by their manufacturer

3.5 Asset Criticality

3.5.1 Protection and Control Relays

An interpretation of the criticality of a protection or control system is dependent upon the type of failure considered and the potential consequences of that failure (refer also Section 3.6). A ranking in terms of the potential value of unserved energy (VUE) in case of outage of the associated primary plant or network element (for example, due to spurious operation of the protection system) is the usual approach as this is statistically the most likely impact of protection (or control) asset failure. The "relative base" criticality thus determined may be adjusted by the asset condition and an assessment of device availability (refer Section 5.5.1) to determine relative asset risk.

Figure 16 provides a summary of the relative base criticalities of in-service protection and control relays, classified by relay technology type. The applied interpretation of relative base criticality is as per

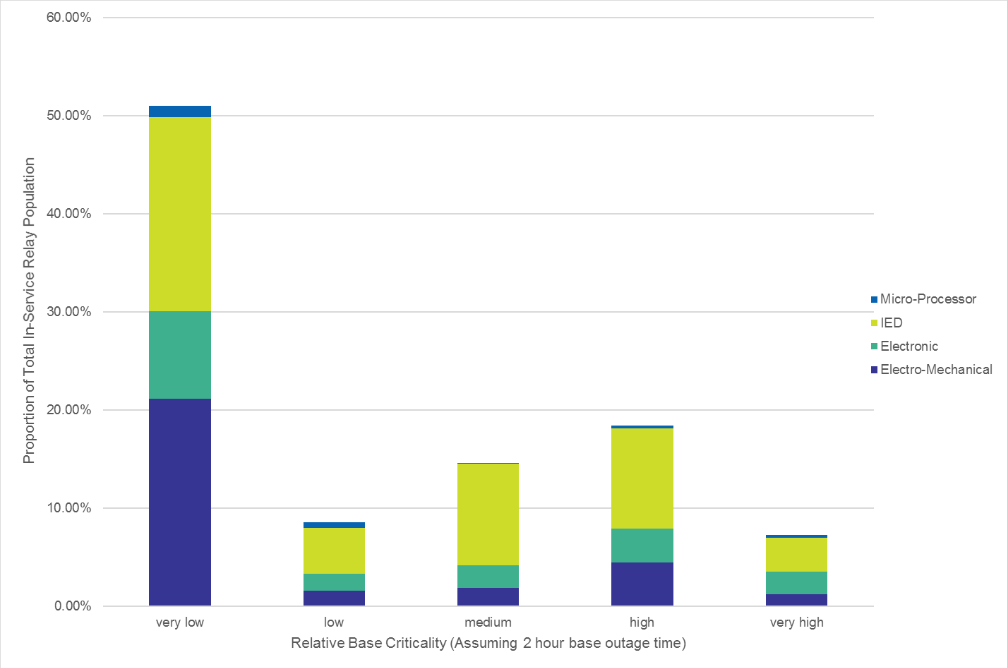

Figure 15: Relative Base Criticality of In-Service Protection and Control Relays, classified by relay technology type

The applied interpretation of relative base criticality is shown in Table 1.

Table 1- Interpretation of Relative Base Criticality

Criticality Bands		**Definition**
1	Very Low	Potential VUE < 0.3 times Scheme Replacement Cost
2	Low	Potential VUE is between 0.3 – 1.0 times of Scheme Replacement Cost
3	Medium	Potential VUE is between 1.0 - 3 times of Scheme Replacement Cost
4	High	Potential VUE is between 3 -10 times of Scheme Replacement Cost
5	Very High	Potential VUE exceeds 10 times of Scheme Replacement Cost

3.5.2 Remote Terminal Units

The consequence of a failure of a zone substation RTU has in general a limited effect on the primary network availability and performance. However, total RTU failure requires that the station be manned until it can be repaired or replaced, which does increase operational costs and reduce operational efficiencies.

Availability of the RTU is necessary for correct operation of station DFA (distributed feeder automation) schemes. In case of total RTU failure, the DFA schemes originating at that station will not operate, resulting in prolonged outages for customers in case of distribution network faults. For this reason, the primary measure of the criticality of an RTU is the potential for preventable customer outages resulting from mal-operation of the DFA system in case of RTU failure.

3.5.3 Legislation and Regulatory Requirements

As an Electricity Distribution Network Service Provider (DNSP) in Victoria, AusNet Services must meet the following obligations:

3.5.4 Electricity Safety Act (Section 98(a))

The Electricity Safety Act (section 98(a)) requires AusNet Services to "*design, construct, operate, maintain and decommission its supply network to minimise, so far as practicable, the hazards and risks to the safety of any person arising from the supply network; having regard to the:*

a) Severity of the hazard or risk in question; and
b) State of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and
c) Availability and suitability of ways to remove or mitigate the hazard or risk; and
d) *Cost of removing or mitigating the hazard or risk*"

3.5.5 Electricity Distribution Code (Section 3.3.1(b))

As per Section 3.3.1 (b) of the Electricity Distribution Code, AusNet Services are required to:

"*Develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:*

- *To comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;*
- *To minimise the risks associated with the failure or reduced performance of assets; and*
- *In a way which minimises costs to customers taking into account distribution losses*"

3.5.6 National Electricity Rule (Clause 6.5.7)

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to propose capital expenditures necessary to:

- "*meet or manage the expected demand for standard control services over that period;*
- *Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
- *Maintain the quality, reliability and security of supply of standard control services; and*
- *Maintain the reliability, safety and security of the distribution system through the supply of standard control services*"

3.6 Asset Performance

Any protection or control system failure is associated with one of three (3) possible failure effects, detailed in Sections 0, 3.6.2 and 3.6.3. Nearly all protection and control system failure consequences occur as a result of failure effects 0 and 3.6.2.

3.6.1 Spurious Operation

A spurious operation is an undesired operation of a protection or control relay that occurs in the absence of a target fault condition or control command. A spurious protection operation can present as either:

- Operation under load when there is no fault, or
- Over-operation for (non-target) faults, leading to an outage of unaffected lines

A failure of this type results in an unnecessary network outage and an unserved energy consequence. The associated economic risk, evaluated on a "per relay" basis, is dependent upon:

- The criticality (in terms of the value of energy at risk) of the primary equipment protected (or controlled) by the protection scheme incorporating the failed device
- The time taken to diagnose and repair the failure, and restore the network to normal operation
- The cost of any associated engineering investigation, repair or replacement activity

The propensity for spurious operation is technology dependent and, for any particular relay technology, considered to be constant throughout the service life of the asset (i.e. independent of asset condition). Non-digital (electromechanical or static electronic) relays are slightly more likely to experience spurious operation due to component failure, while digital relays (intelligent electronic devices [IEDs] and first-generation micro-processor based relays) are more likely to operate spuriously as a result of human, design or logical error rather than component failure.

The benefit of a better condition asset over a poorer condition asset in this context is primarily attributed to a reduction in time taken to diagnose and repair an equipment or logical error. A C5 "Very Poor" condition asset is estimated to take up to 6 times longer to return to normal service than a C1 "Very Good" condition asset.

Spurious operation of a protection system is the most prevalent secondary asset failure effect experienced on the AusNet Services' distribution network.

3.6.2 Diagnosed Asset Failure

A diagnosed failure refers to any failure within the protection or control system that is recognised by the network operators either by assertion of a condition or status alarm, or as a result of an investigation, that has not (yet) resulted in a direct consequence, but requires that a network outage be taken in anticipation of, or to facilitate, repair. The associated economic risk, evaluated on a "per relay" basis, is quantified in the same way as 0.

Modern, IED- based schemes have comprehensive self-monitoring, diagnostic and alarming capability which makes them slightly more likely to experience diagnosed failure compared to schemes based on non-digital relay technologies, however the consequences associated with diagnosed failure of a digital scheme is generally significantly less, and quite often allows for a failure that would otherwise be associated with spurious operation or protection system unavailability to be repaired prior to the spurious operation or "failure to operate" incident occurring.

As for 0, the benefit of a better condition asset over a poorer condition asset in this context is attributed to a reduction in the time taken to locate and repair the failure and restore the system to normal operation. A C5 "Very Poor" condition asset is estimated to take up to 6 times longer to repair in case of failure than a C1 "Very Good" condition asset.

3.6.3 Undiagnosed Asset Failure ("Protection system Unavailability")

Undiagnosed failure refers to a failure within a protection or control system that is not recognised by network operators, for example because there is no capability within the protection system to diagnose or indicate the failure, no alarm, an alarm is not recognised or mal-attributed, or because a periodic fault-finding investigation has not been completed since the failure occurred. The undiagnosed failure renders the system incapable of operating as required in the event of a fault or primary asset failure, in which case the protection system is referred to as "unavailable".

Failure of a protection system to operate on demand is associated with potentially catastrophic consequences in terms of safety, environment and collateral damage due to persistence of a fault or undesired network operational state. Any single occurrence may be considered unacceptable. The contribution of the secondary asset to network risk in this context is highly dependent upon the probability that the protected (or controlled) network element experiences a fault or primary asset failure – the more likely the fault, the more significant the contribution to network risk. The economic risk, assessed on a "per system" (rather than "per relay") basis, manifests as an additional consequence input to the primary/network risk model. It is dependent upon:

- The degree of redundancy inherent within the failed protection or control system
- The criticality and capital value of the primary equipment protected (or controlled) by the failed system
- The geographic location of the network element protected (or controlled) by the failed system, and the likelihood and consequences of personnel or public exposure to the effects of a catastrophic asset failure or prolonged network fault
- The time taken to restore the network to normal operation (which may be considerable in the case of catastrophic asset failure)
- The cost of any associated contingency, investigation, legal, asset repair and replacement activities

This risk is difficult to quantify and a qualitative or semi-quantitative approach to risk evaluation and management is often applied in preference to an economic model. In applying such an approach, AusNet Services makes reference to Australian Standard AS IEC 61508 "Functional safety of electrical/electronic/programmable electronic safety-related systems".

The management of unavailability risk is a primary determinant of scheduled asset maintenance requirements – where the contributing failure modes may be only be detected via scheduled fault finding investigations, the frequency at which those investigations are undertaken directly impacts the probability of the protection system being in an unavailable state between inspections. Asset maintenance strategies are currently under review to ensure maintenance of an acceptable and economically justified availability performance level.

IED-based schemes have comprehensive self-monitoring, diagnostic and alarming capability, which makes them less likely to experience undiagnosed failure compared to non-digital systems. The modernisation score component of the asset health score is an indicator of the relative availability of the asset in service. An asset with a worse (4 or 5) modernisation score is more likely to experience unavailability under the existing maintenance regime compared to an asset with a better (1 or 2) modernisation score. Asset replacement is often a better technical and economic alternative to decreasing applied fault-finding inspection intervals beyond existing protocols, particularly for high-criticality assets, and facilitates realisation of secondary benefits in terms of network modernisation.

In practice, design standards routinely employed throughout AusNet Services electricity networks (consistent with industry practice), combined with a structured periodic maintenance strategy (Section 5.2), minimises both the likelihood and impact of isolated undiagnosed asset (device) failure well below that of failure effects 0 and 3.6.2.

3.6.4 Remote Terminal Units

RTU failure can be divided into two types: hardware failure, and software constraint.

Hardware failure requires replacement of the failed component. A failed input, output or analogue card results in the loss of a subset of telemetry data supplied to SCADA via the RTU. Failure of the microprocessor or DC supply components results in the loss of visibility of the entire zone substation, and necessitates that the station be manned for manual supervision and control pending RTU repair. When no spares are available, as may be the case with older, obsolete units, replacement of the entire RTU is necessary (a costly, time and labour intensive exercise).

Software constraint is generally associated with a longer repair time due to lack of support or long lead/response times from the unit manufacturer. Manufacturer product support is thus an important aspect of software and firmware management. Without support, the RTU is associated with an increased risk of software glitches due to lack of options for firmware upgrade. It is for this reason that obsolescence and manufacturer support are a key input to asset condition assessment.

Both hardware failure and software constraint are declared failure modes, that are recognisable to the network operator via assertion of alarms or observable unit non-responsivity.

4 Other Issues

4.1 Emerging Technologies and the Evolving Energy Landscape

Protection and control asset management decisions are considered in the context of both AMS 20-01 (AusNet Services Distribution Asset Management Strategy) and AMS 20-13 (AusNet Services Enhanced Network Safety Strategy). These documents provide guidance on the approach taken by AusNet Services to accommodate recognised emerging technologies and the evolving energy landscape, including bushfire mitigation (specifically in the context of the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016), and the increasing penetration of domestic and commercial solar generation and energy supply alternatives.

AMS 01-06 (AusNet Services Risk-Based Asset Management Guidelines) provide a high level overview of the risk-based approach to asset management adopted by AusNet Services.

4.1.1 Rapid Earth Fault Current Limiters (REFCL) and Bushfire Mitigation

The introduction of REFCL technologies within 22 zone substations across the AusNet Services network will continue to drive both technological change and bulk asset replacement activities over the next 10 years. The integration of REFCL technologies represents a significant technological change in the management of earth faults on the distribution network. AusNet Services has developed, and continues to refine a comprehensive 22kV earth fault management strategy (PPD 01-07) that will contribute to asset management decisions relating to 22kV asset protection and control schemes. This policy will directly impact decisions relating to the application and replacement of Master and Backup Earth Fault (MEF and BUEF) protection schemes in particular. For this reason, a significant number of MEF and BUEF replacement activities proposed to occur within the next 10 years will occur as part of, or in conjunction with, REFCL installation projects.

4.1.2 Emerging Technologies

The rapid evolution of digital and other emerging technologies will continue to influence asset management decisions relating to protection and control systems.

The IEC61850 standard and associated technologies will continue to mature throughout the next 10 years, and its integration within increasingly “smart” electricity network and equipment will continue to increase. The REFCL program will provide opportunities to research and develop process bus applications for 22kV protection and control schemes, in particular, as a way of managing increasing demand for inter-relay communications. This is also anticipated to increase the requirement and criticality of centralised digital interface assets (referred to as Digital Interface Cubicles (DICs)) for the management of data traffic.

Digital Interface Cubicles also provide the capability for remote engineering access to protection and control assets, allowing relay data to be accessed from a centralised location. This capability provides opportunities to further improve operational efficiencies and decrease network incident investigation and response times. As only IEDs are capable of providing a remote engineering interface, increasing reliance on remote operability will continue to drive replacement of older assets in key locations.

The capability and specification of relays will be affected by the increasing prevalence and economic viability of alternative instrument transformer technologies, including optical CTs.

Increasing pressure from distributed generators, combined with evolution in telecommunication technologies, is already necessitating research and development of 3G and 4G solutions for protection signalling applications.

Rapid technological evolution places increasing demands on staff capabilities, and ongoing investment in staff training and education, and industry knowledge management in general, will become increasingly critical.

5 Risk and Options Analysis

The following strategies are employed by AusNet Services to manage the risks identified in Section 3.6:

5.1 Design

All protection and control schemes deployed throughout the electricity network are designed, as a minimum, in accordance with the Station Design Manual SDM 06.

In particular:

- Redundancy in design minimises the probability of protection and control system unavailability by diversifying critical paths and removing common points of failure. Redundancy in design also minimises the impact of secondary maintenance activities on primary network operations
- Design standardisation maximises engineering familiarity with in-service systems and the associated failure modes, which minimises the potential for failure due to human error, maximises the capability of personnel to operate and maintain the equipment and identify and rectify faults, while facilitating the efficient and economic management of spare parts, equipment and tools. Standardisation also ensures in-service assets consistently operate in compliance with applicable legislation, standards and best industry practice.

Asset health assessment incorporates assessment of each protection and control device and application in terms of compliance with the station design manual and current equipment standards. The poorest condition assets are generally associated with minimal (or no) compliance with the station design manual and/or varying degrees of incompatibility with current design standards.

The SDM details design and performance requirements for the complete protection system associated with each type of network element. Design standards thus focus on the design of a complete protection system, including X, Y and backup protection schemes, as well as primary plant control and monitoring schemes, required for use in each type of network application (i.e. each piece of primary equipment). Proactive replacement activities (refer Section 5.3) thus involve replacement of consolidated protection and control systems, rather than isolated protection scheme/device replacements. This minimises the cost of design, maximises compliance of the replacement system with design standards and maximises the efficiency and realised benefits of the capital replacement activity.

5.2 Scheduled Periodic Inspection and Maintenance

Protection and control assets are maintained in accordance with PGI 02-01-04 and SPP 02-00-01. Regular inspection, testing and maintenance facilitate timely diagnosis of asset failures with the potential to lead to spurious operation, system unavailability or other operational instability.

Maintenance regimes applicable to protection and control relays are current under review to ensure that the maintenance program achieves an appropriate balance between operational efficiency and asset risk.

5.3 Proactive Asset Renewal and Spare and Obsolescence Management

Strategic asset renewal, spare and obsolescence management ensures that in-service assets are associated with a level of operability and maintainability sufficient to

- Minimise the potential for failures associated with human error
- Optimise the efficiency of fault response and investigation activities

- Minimise time and cost associated with failed asset repair or replacement

Secondary benefits of strategic asset renewal include:

- Facilitate progressive migration towards technologies with improved self-monitoring, alarm and diagnostic capabilities, that maximises the capability to detect, isolate and repair asset failures before they can affect operation of the primary network;
- Provide opportunities to modernise and enhance the capabilities of the electricity network, including enhancing capabilities for the "smart" and efficient control, monitoring, maintenance and management of primary network equipment;
- Provide a mechanism for generating spares for assets no longer available for purchase, but for which short-term retirement of the entire fleet is considered impracticable or uneconomic.

Asset renewal is considered, in accordance with legislated obligations discussed in Section 3.5.2, when alternative risk management approaches (5.1, 5.2) are uneconomic, impractical or insufficient to satisfactorily maintain or reduce network risk. The renewal program proposed for the 2022-26 regulatory period, and the options considered in the development of this program, is described in Section 5.4.

As discussed in Section 5.1, proactive replacement activities involve replacement of consolidated protection and control systems, rather than isolated protection schemes/devices. Thus, multiple assets are replaced under each proactive replacement activity. Individual relays are replaced independently only upon failure.

Similarly, the most appropriate, efficient and economic option when upgrading SCADA services to zone substations from [C.I.C] and [C.I.C]-type RTUs is to replace the entire remote terminal unit, including station HMI, rather than maintain multiple units in service.

5.4 Options Analysis

Options analysis is performed to determine where asset renewal may be considered necessary, prudent or of more economic advantage than alternative risk management strategies. The overall aim of any proactive capital activity is to maintain or minimise risk associated with poor condition or restricted capability assets.

Primary asset renewal projects often necessitate secondary asset reconfiguration, replacement or upgrade. It is most efficient to co-ordinate the replacement of primary and secondary assets whenever possible. An over-arching strategy for protection and control equipment is to complete secondary asset renewals coincident with primary asset renewal, refurbishment or augmentation works as far as practicable in order to realise capital and operational efficiencies and minimise network disruption.

5.5 Options analysis - Protection and Control Relays

A two-step approach was applied in development of the options analysis for 2022-26 CAPEX forecast:

- A semi-quantitative risk-based decision matrix was used to identify and prioritise the poorest condition, highest criticality assets likely to benefit from replacement (5.5.1)
- An economic assessment was applied to the identified poor condition, high criticality assets to test economic viability of asset replacement during the 2022-2026 regulatory period (5.5.2)

Only those assets located at stations at which no significant primary asset renewal or augmentation works are anticipated to occur before 2025 were assessed for inclusion in the independent protection and control asset renewal program for the 2022-26 regulatory period.

5.5.1 Identification and Prioritisation of Assets for Renewal

Poor condition, high risk assets were identified and prioritised for replacement by 2025 via application of a semi-quantitative risk-based decision matrix. All three possible failure effects (0, 3.6.2 and 3.6.3) were considered in development of the decision matrix.

Each asset was associated with a base potential value of unserved energy determined by the criticality of primary equipment it protects (or controls). This value was multiplied by an outage time of (2* $MTTF_{factor}$) hours, where $MTTF_{factor}$ is a weighting on the nominal expected outage time (2 hours) determined by the condition of the secondary asset (Table 2). The result is an estimate of the potential energy at risk in case of spurious operation (0) or diagnosed asset failure (3.6.2). The condition adjusted potential value of unserved energy, stated in terms of the scheme replacement cost (SRC)[1], formed the vertical axis of the decision matrix.

Table 2: $MTTR_{factor}$ is determined by asset condition

mttr base	2	hours			
condition	c1	c2	c3	c4	c5
mttr factor	1	1	2	3	6

(A base 2 hour switching time is assumed for all assets in the event of failure)

The horizontal axis of the decision matrix is a rating scale determined by the primary station risk (transformer risk was used as proxy) and the capability and reliability of the associated secondary system. A poor score in the availability consequence rating (4 or 5) applies where a low-availability system with minimal fault diagnostic/analytical capability is applied at a station with high primary asset risk and/or poor primary asset condition. Protection assets in this region of the decision matrix are considered more likely to experience an operational demand while in an unavailable state (failure effect 3.6.3), and thus present an increased safety, environmental and collateral damage risk in case of primary asset failure or network fault.

The applied decision matrix (Table 3) was intended to:

- Facilitate estimation of the optimal time for replacement of poor condition assets based on economic and safety risk
- Economically maximise protection system capability and reliability for high risk and/or poor condition (primary) network assets

Table 3: Semi-Quantitative Risk-Based Decision Matrix used to identify and prioritise poor condition, high risk assets for replacement

		Availability Rating				
		1	2	3	4	5
Criticality Band	5	0%	0%	6%	6%	2%
	4	0%	5%	6%	3%	0%
	3	0%	7%	4%	1%	1%
	2	0%	4%	4%	1%	0%
	1	0%	15%	29%	5%	2%

[1] The Scheme Replacement Cost (SCR) is the estimated cost of replacement of an isolated protection scheme (i.e. 1 relay and associated peripheral equipment). It should not be confused with the Unit Replacement Cost (URC), which is the estimated cost of replacement of the complete protection and control system associated with a particular piece of primary equipment, including X, Y and back-up protections, as well as any control or on-line monitoring equipment necessary for the application, according to the Station Design Manual.

Maintain In Service
Plan for replacement by the end of the 2032-36 EDPR period; include for coincident replacement if economic within primary asset replacement, station refurbishment or network augmentation activities occuring between 2018 and 2035.
Plan for replacement by the end of the 2027-31 EDPR period; include for coincident replacement if economic within primary asset replacement, station refurbishment or network augmentation activities occuring between 2018 and 2030.
Plan for replacement by the end of the 2022-26 EDPR period; include for coincident replacement if economic within primary asset replacement, station refurbishment or network augmentation activities occurring between 2018 and 2025.

A preliminary CAPEX forecast was developed allowing for replacement of all assets identified for planned replacement within 5 years that are located at stations for which no primary asset renewal or augmentation works are anticipated to occur prior to 2025. Assets identified by condition assessment to be associated with a non-compliance issue were added to the program if not already identified via application of the decision matrix. Assets located at stations where primary asset renewal or augmentation works are anticipated to occur prior to 2025, and that were identified for replacement within 10 years, were recommended for inclusion in those planned renewal or augmentation works and excluded from further analysis.

5.5.2 Economic Benefit Analysis

The preliminary CAPEX forecast (from Section 5.5.1) was subject to further analysis to assess economic viability and advantage. The options analysis compared the costs and benefits of protection and control system replacement to the cost of maintaining each of the constituent assets in service. Only failure effects 0 and 3.6.2 were considered in the economic analysis.

As the preferred approach is to replace complete protection and control systems, rather than individual schemes, the costs and benefits were compared on a program and/or station level, rather than individually by equipment, in consideration of the Unit (System) Replacement Cost (URC)[2] (i.e. the cost of replacement was assessed against the summated benefits of replacement of groups of individual protection and control relays).

The preliminary CAPEX program was adjusted in consideration of both the outcome of the economic analysis and the requirements detailed in Section 3.5.2 to achieve the final CAPEX proposal.

5.6 Option analysis - Remote Terminal Units (RTUs)

A standard economic, cost-benefit options analysis was applied to determine the most appropriate asset management strategy for RTUs.

The contribution to station risk by each in service RTU was estimated for two failure events:

- Failure of a critical alarm point, or failure to diagnose the source of a critical alarm, resulting in a major system incident
- RTU outage resulting in failure of DFA system to operate in case of feeder fault

The associated risk is significant at stations where an [C.I.C] RTU is in service, but very low where more modern systems are employed. The estimated risk was proportional to the number of customers supplied from

[2] As opposed to the Scheme Replacement Cost (SRC), the Unit Replacement Cost (URC) is an estimate of the (direct) cost of proactive replacement of an integrated protection and control system, including X, Y and backup protections, as well as any associated control or monitoring systems necessary for operation of the associated primary plant. The URC allows for replacement of multiple individual devices and associated peripheral equipment, as per Station Design Manual (refer Section 5.1).

the zone substation. Stations with highest residual risk – i.e. stations with [C.I.C] RTUs – were identified for replacement by 2025.

It should be noted that works occurring under the REFCL program do not include RTU replacement, although in cases where the existing RTU has insufficient capacity to support the REFCL installation, partial system augmentation may occur. Complete replacement of legacy RTUs is the preferred approach, and additional works will be required at REFCL stations to accommodate this. The provided forecast allows for these additional works where necessary.

5.7 Forecast Summary

The proposed program for the next 10 years allows for targeted, proactive and economic replacement of poor condition, high risk protection and control systems under the following activity categories, consistent with legislation and regulatory requirements detailed in Section 3.5.2:

- Replacement of high risk 66kV line protection systems incorporating poor condition static-electronic and first-generation microprocessor-based distance protection relays (PQ741 and RAZOA-type devices)
- Replacement of high risk transformer and 66kV bus protection systems incorporating poor condition and/or reduced availability electromechanical, static-electronic and first-generation micro-processor based transformer protection relays (KBCH120, D21SE2, D21SE3, DUOBIAS, D21, D202-type devices), and electromechanical and static electronic high-impedance bus protection relays (CAG34, RADHA and RAKZB-type devices)
- Replacement of high risk 22kV bus, back-up earth fault (BUEF) and master earth fault (MEF) protection systems incorporating poor condition electromechanical and static-electronic high-impedance bus protection relays (RADHA, 2V73, GROUP, 2V47, SPAJ and RXZK-type devices), electronic bus distance protection relays (DIST-2987-type devices), electromechanical, static electronic and early generation digital BUEF protection relays (DCD, ARGUS C, GROUP and CMUR-type devices) and electromechanical and static-electronic based MEF protection relays (GROUP and ARGUS-type devices).
- Replacement of obsolete and non-compliant [C.I.C] relay-based 22kV feeder protection schemes
- Replacement of obsolete, high risk AVE-type voltage regulation relays
- Replacement or upgrade of restricted capability voltage regulation control systems at zone substations affected by significant load growth, and as required to accommodate ongoing penetration of low voltage distributed generation
- Continuation of [C.I.C] RTU replacement program

Replacement of approximately 70% of identified poor condition, high risk or non-compliant protection and control assets will occur as part of complex station refurbishment or network augmentation activities.

6 Asset Strategies

6.1 New Assets

- All new and replacement assets will be designed In accordance with the Station Design Manual and current design standards, undertake replacement of complete protection systems (i.e. X, Y, backup and necessary control and monitoring systems) associated with individual items of primary plant/network sections, rather than individual protection schemes/relays
- Replacement activities shall be incorporated within primary plant replacement, station refurbishment or network augmentation activities as far as practicable, in order to maximise operational efficiency and minimise network disruption

6.2 Maintenance

- Continue to maintain protection and control assets as per PGI 02-01-04 and the SPP 02-00-01 suite of documents
- Maintain PGI 02-01-04 and the SPP 02-00-01 suite of documents consistent with the outcomes of ongoing Enhanced Data-Driven Asset Management (EDDAM) studies
-

6.3 Spares

- Continue to maintain sufficient spares to ensure ongoing maintainability of in-service devices
- Maintain decommissioned assets in appropriate working condition as spares, as required to ensure the ongoing serviceability of in-service, poor condition/obsolete assets pending retirement
- Continue to consider device obsolescence, as advised by asset manufacturers and suppliers, in preparation of asset replacement strategies

6.4 Replacement

Prioritise proactive replacement of:

- High risk 66kV line protection systems incorporating obsolete and/or poor condition static-electronic and first-generation microprocessor-based distance protection relays (PQ741 and RAZOA-type devices)
- High risk transformer and 66kV bus protection systems incorporating obsolete and/or poor condition electromechanical, static-electronic and first-generation micro-processor based transformer protection relays (KBCH120, D21SE2, D21SE3, DUOBIAS, D21, D202-type devices) and electromechanical and static electronic high-impedance bus protection relays (CAG34, RADHA and RAKZB-type devices)
- High risk 22kV bus, back-up earth fault (BUEF) and master earth fault (MEF) protection systems incorporating obsolete and/or poor condition electromechanical and static-electronic high-impedance bus protection relays (RADHA, 2V73, GROUP, 2V47, SPAJ and RXZK-type devices), electronic bus distance protection relays (DIST-2987-type devices), electromechanical, static electronic and early generation digital BUEF protection relays (DCD, ARGUS C, GROUP and CMUR-type devices) and electromechanical and static-electronic based MEF protection relays (GROUP and ARGUS-type devices).
- 22kV feeder protection schemes incorporating non-compliant and obsolete [C.I.C] relays
- Obsolete, high risk AVE-type voltage regulation relays

- Restricted capability voltage regulation control systems at zone substations affected by significant load growth, and/or as required to accommodate ongoing penetration of low voltage distributed generation
- Obsolete and unreliable [C.I.C] and [C.I.C]-type remote terminal units

6.5 Research and Development

- Evaluate process bus applications for use at 22kV
- Continue to refine 22kV earth fault management strategy in response to evolving technologies
- Investigate opportunities and strategies for integrating non-conventional instrument transformers
- Research and develop 3 and 4G solutions for protection signalling (including backup intertrip) applications to address increasing penetration of distributed generation
- Investigate ways to improve primary asset monitoring and maintenance using existing secondary infrastructure