Asset Management Plan

Transmission Protection and Control

Record Number: R478117

Version: 1.0

Date: October 2017

Authorisations

Action	Name and title	Date
Prepared by	Robert Smith, Secondary Asset Strategy Team Leader	30 August 2017
Reviewed by	Guy Debney, GHD Consultant	25 September 2017
Authorised by	Darryl Munro, Primary Asset Strategy Team Leader	30 October 2017
Review cycle	30 months	

Responsibilities

This document is the responsibility of the Asset Strategy Team, Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

Please contact the Asset Strategy Team Leader with any queries or suggestions.

- Implementation All TasNetworks staff and contractors.
- Compliance All group managers.

Record of revisions

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1 Purpose

The purpose of this document is to describe for the transmission network protection and control assets:

(a) TasNetworks' approach to asset management, as reflected through its legislative and regulatory obligations and strategic plans;

(b) The key projects and programs underpinning its activities; and

(c) Forecast capital and operational asset numbers, including the basis upon which these numbers are derived.

2 Scope

This document covers the strategic protection and control relays installed within TasNetworks extra high voltage (EHV) substations that are used for the protection and control of:

(a) bus couplers;

(b) busbars;

(c) capacitor banks;

(d) HV feeders;

(e) station services transformer;

(f) network and supply transformers; and

(g) transmission lines.

3 Strategic alignment and objectives

This asset management plan has been developed to align with both TasNetworks' Asset Management Policy and strategic objectives. This management plan describes the asset management strategies and programs developed to manage the distribution overhead switchgear assets, with the aim of achieving these objectives.

For these assets the management strategy focuses on the following objectives:

- Safety will continue to be our top priority and we will continue to ensure that our safety performance continues to improve
- Service performance will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet regulatory requirements
- Cost performance will be improved through prioritisation and efficiency improvements that enable us provide predictable and lowest sustainable pricing to our customers
- Customer engagement will be improved to ensure that we understand customer needs, and incorporate these into our decision making to maximise value to them
- Our program of work will be developed and delivered on time and within budget

The asset management policy and strategic objectives are outlined within the Strategic Asset Management Plan. In alignment, with the Strategic Asset Management Plan, this asset management plan is based on the interdependence between, the Plan, Do, Check, Act components of good asset management practice.

4 Asset information systems

4.1 Systems

TasNetworks maintains an asset management information system (AMIS) that contains detailed information relating to the transmission protection and control asset population. AMIS is a combination of people, processes and technology applied to provide the essential outputs for effective asset management.

4.2 Asset information

Asset information is recorded in the WASP asset register, which is used for asset attributes, spares management, works scheduling and defect management. The asset breakdown structure shows the physical relationship of the protection and control relays, attached to a logical scheme which is then linked to the primary asset or substation that the scheme is protecting. BASIX is used to program and record maintenance activities for primary and secondary assets. WASP and BASIX are to be replaced in early 2018 by SAP, this will provide improved asset information.

5 Asset description

A protection and control scheme is a grouping of relays combining to protect and control a defined electrical circuit. Mostly within the protection and control scheme the relays are duplicated to provide redundancy and are designed to also provide backup to adjacent circuits ensuring that no part of the transmission system is unprotected especially during the failure of another protection and control scheme.

Protection relays are required to detect and isolate faults on the power system to minimise damage to expensive equipment, maintain stability of the power system by disconnecting only the faulted part of the electricity network and alleviate the risk of injury or death to the public or personnel by rapidly disconnecting live primary equipment.

Control relays provide automated commands to control primary equipment such as changing transformer tapping or voltage synchronised circuit breaker re-closure. A control relay is also used to interface to the substation SCADA system to provide operational metering and remote control of substation switchgear.

Modern protection and control relays are multifunction providing extensive fault detection algorithms, disturbance recording, fault location, remote interrogation and direct SCADA integration. As processing power increases, the control functionality is able to be incorporated into the protection relay providing cost and performance efficiencies.

This section provides high-level information on TasNetworks' transmission protection and control assets, including age and type profile, and performance, condition and risk summaries.

5.1 Bus coupler protection and control

EHV bus coupler protection schemes provide control of the EHV bus coupler bay such as network synchronisation, bay interlocking and control, and operational metering. Where a single EHV busbar protection scheme is installed, non-directional impedance or overcurrent protection is provided on the EHV bus coupler circuit to split the buses prior to the remote backup protection operating which minimises the number of circuits disconnected by the busbar fault. For modern scheme, this is all achieved by one multifunction protection and control relay within the bus coupler protection and control scheme.

HV Bus coupler protection and control schemes are usually an integral part of the busbar tripping and blocking schemes. It also has overcurrent and earth fault protection to back up the busbar and feeder protection. A single multifunction relay performs all control and metering of the bus coupler circuit as well as protection. On some H-type HV busbar arrangements, the bus coupler protection relay performs an automatic closure of the bus coupler on the loss of one transformer.

5.2 Busbar protection

TasNetworks has traditionally installed single EHV busbar protection schemes in the transmission substations and in the event of a busbar protection failure or outage, backup protection is provided by the remote transmission line protection schemes and reverse-direction impedance protection of network transformer protection schemes. The under-impedance protection of the bus coupler protection scheme is set to operate before the remote backup protection so as to disconnect the individual busbars and minimise the amount of circuits affected. Most EHV busbar protection schemes, specifically low impedance, also provide circuit breaker fail (CBF) protection.

In some instances the backup clearance time is not sufficient to meet the requirements of clause S5.1.9 of the National Electricity Rules (NER). In these cases a duplicate EHV busbar protection scheme is required and is determined by site criticality, plant damage characteristics and system stability studies. The duplicate busbar protection scheme will be of a different model to the main scheme to ensure full redundancy. Only single CBF protection is required which is provided by only one of the duplicated EHV busbar protection schemes.

Most EHV busbar protection schemes are low impedance measurement type although, on non-selectable busbar arrangements where current circuits are not required to be switched, high impedance protection is selected due to the lower installation and maintenance costs.

There are five basic types of HV busbar protection schemes in service in TasNetworks substations:

(a) High impedance differential protection;

(b) Frame leakage protection with transformer neutral current check;

(c) Switchboard arc detection with current check;

(d) Switchboard pressure surge with current check; and

(e) Transformer and feeder overcurrent and earth fault protection blocking. This type of protection is not included in the busbar protection population as it is incorporated in the transformer incomer and feeder protection.

Low impedance busbar protection has not been used on TasNetworks' HV busbars due to the additional cost of the low impedance relays and the number of feeder circuits the relays can accommodate.

5.3 Capacitor bank protection and control

TasNetworks has a policy to install diverse protection relays with duplicated functions, designated as the 'A' and 'B' relays, in all EHV and HV shunt capacitor bank protection and control schemes. A typical capacitor bank protection and control scheme includes the following functions:

(a) Overcurrent and earth fault protection;

(b) Over and under voltage protection;

(c) Neutral unbalance protection;

(d) Harmonic overload protection;

(e) Point-of-wave circuit breaker control (EHV installations only); and

(f) Bay interlocking and control.

In addition all HV capacitor banks have a control relay to automatically switch in and out the capacitor bank(s) based on voltage or MVAr set points.

In some older schemes, these functions may be provided by discrete protection relays within the capacitor bank protection and control scheme or included in multifunction relays.

5.4 HV feeder protection and control

The HV feeder protection lies on the edge of the transmission network but protects the beginning of the distribution network the voltage levels for this interface are typically 22kV and 11kV. A feeder protection and control scheme typically includes overcurrent, earth fault and sensitive earth fault protection and automatic breaker re-closure functionality. Feeder differential schemes are incorporated for substations suppling the Hobart CBD. These schemes do not require redundancy under the NER and in modern installations the protection and control functions are incorporated within a single relay. Backup protection is provided by the transformer protection scheme.

TasNetworks install current differential protection on sub-transmission feeders which is not included in this asset management plan as this protection was under the ownership of the distribution network service provider prior to the forming of TasNetworks and on some major industrial customer feeders, differential protection is installed; however, ownership and management of the differential protection is the responsibility of the feeder circuit owner as the connection point is usually at TasNetworks' HV switchboard.

5.5 Station services transformer protection and control

The station services transformer protection and control scheme typically includes a fuse switch or circuit breaker with overcurrent and earth fault protection. Often, this protection and control scheme is the same as the feeder protection and control schemes and in some HV substations the station services transformer is connected directly to an outgoing feeder circuit where the feeder protection and control scheme is used to also protect the station services transformer. The station services circuits containing fuse switches or are connected to an outgoing feeder are not presented in this asset management plan as station services protection and control schemes.

5.6 System protection

A system protection scheme is required to monitor sections of the transmission system to detect unusual conditions, other than faults, that can affect the secure operation of the power system. Such conditions include circuit overloading, frequency deviation, under voltage and network islanding. System protection schemes ensure compliance with clause 4.2.4 (a) (2) of the National Electricity Rules (NER) which specifies that '*provision shall be made to ensure that the power system will return to satisfactory operating state following the occurrence of any credible contingency event*'. On its operation, the system protection scheme will either disconnect load or generation from the transmission system to return the power system to stable operation.

Since 1985 Tasmania has installed under frequency load shedding (UFLS) schemes around the state to monitor the system frequency and trip defined blocks of load to mitigate the loss of large generators. Some of these schemes are located at major industrial load sites and following the segregation of the Tasmanian power utilities, over frequency generator shedding (OFGS) schemes were installed in some substations to disconnect generation following the loss of large loads.

In 2005 TasNetworks joined the National Electricity Market (NEM) with the installation of the Bass Straight DC cable. In order to secure the frequency operation of the Tasmanian power system from an unplanned disconnection of the cable, the frequency control system protection scheme (FCSPS) was installed. Additionally, for Hydro Tasmania to transfer more generation to the Bass Straight cable connection point at George Town over non-firm transmission lines, the network control system protection scheme (NCSPS) and backup NCSPS overload protection schemes was installed.

5.7 Transformer protection and control

TasNetworks has a policy to install diverse protection relays with duplicated functions, designated as the ‘A’ and ‘B’ relays, in most power transformer protection and control schemes. The most effective protection function is biased current differential, which monitors the entire transformer and has the advantage of high speed operation so as to meet the fault clearance requirements of the NER.

The transformer protection and control scheme also includes the automatic voltage regulator (AVR) relay with is used to control the on-load tap changer of the transformer so as to maintain an acceptable output voltage to customer loads.

The mechanical Buchholz, tank pressure and temperature devices are generally fitted by the transformer manufacturer and maintained by the TasNetworks Substations team and as such will not form part of this asset management plan.

5.8 Transmission line protection and control

TasNetworks has a policy to install diverse protection relays with duplicated functions, designated as the ‘A’ and ‘B’ relays, in all 110 kV and 220 kV transmission line protection and control schemes. The standard scheme configuration is for both relays to provide current differential protection functionality so as to meet the fault clearance requirements of the NER. However, an impedance based protection function with permissive signalling will also provide the required fault clearance times but can be susceptible to under or over coverage when transmission line parameters or network configurations change. Additionally, impedance based protection elements do not provide full high speed coverage on radial circuits where fault current only flows from one end of the transmission line.

Where a transmission line connects to a customer’s substation or power station, the customer owns the transmission line protection scheme at the customer site. This necessitates the coordination with the customer’s scheme configuration in which duplicated current differential protection is not preferred. The modern protection relays selected by TasNetworks are able to provide both current differential and impedance based protection functions to cater for such configurations.

The standard design of the transmission line protection and control scheme includes a bay control relay which provides the automatic breaker re-closure, synchronising check, bay interlocking and control, and operational metering.

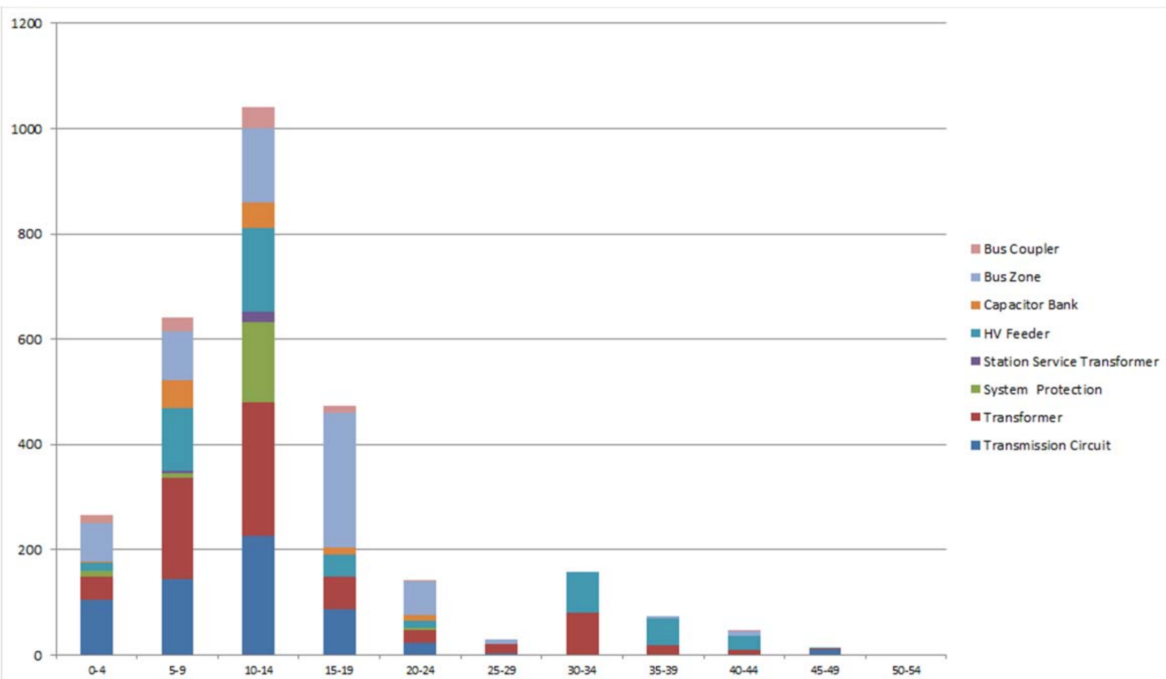
5.9 Protection and control age profile

Table 1 shows the population of protection and control relays and their associated schemes in TasNetworks' transmission system and Figure 1 shows the age profile for the protection and control relays. The economic life of the transmission protection and control relays is 15 years as defined by Sinclair Knight Merz (SKM) in its 'Assessment of Proposed Regulatory Asset Lives' document prepared in August 2013.

Table 1 Transmission protection and control population

Description	Schemes	Relays	Sites
Bus coupler	84	102	35
Busbar	77	642	41
Capacitor bank	35	124	16
HV feeder	355	511	43
Station services transformer	30	26	14
System protection	47	151	32
Transformer	117	701	49
Transmission line	195	585	45
Total	**940**	**2,842**	**56**

Figure 1 Transmission protection and control relay age profile



The majority of TasNetworks' protection and control relays are aged between 5 to 19 years.

5.10 Technology types

The specific protection and control relays addressed in this asset management plan can be differentiated from one another by three main technology types:

(a) Electromechanical relays;

(b) Static relays; and

(c) Microprocessor relays.

5.10.1 Electromechanical

These were the first type of relay technology developed for power systems and operate by mechanical force from the electromagnetic field generated by current flowing in an electric coil. Electromechanical relays have the advantage of being simple in operation and construction, but are not able to monitor their own health or provide fault diagnostics. Protection relays tend to sit for long periods of time between fault operations and mechanical components are susceptible to atmospheric conditions; as a result of this, electromechanical relays tend to seize and often their first operation is slow. Due to this expected reduction in performance and the lack of self-supervision, electromechanical relays require more frequent routine maintenance. Electromechanical relays can only perform single functions and as such a protection and control scheme comprising of electromechanical relays have more components and require more space than modern protection and control schemes.

5.10.2 Static

Static relays were introduced to the transmission system in the 1970s. They have minimal moving parts and use electronic components to perform the selectivity, sensitivity and logical functions. Static relays use electrolytic capacitors in their timing circuits which dry out from the heat generated within the relay and are susceptible to calibration drift over time. Similar to electromechanical relays, static relays are not able to monitor their own health or provide fault diagnostics; this also requires static relays to have more frequent periodic maintenance. Static relays can only perform single functions and as such a protection and control scheme comprising of static relays have more components and require more space than modern protection schemes.

5.10.3 Microprocessor

Microprocessor relays were introduced in the 1990s. They operate by converting analogue current and voltage waveforms into digital quantities, which are then used in mathematical algorithms by the microprocessor to identify the fault conditions. With the increase in processing power, modern microprocessor relays have more capability and operate much faster than earlier microprocessor models. They are able to alarm for internal faults and provide failure diagnostics. They also provide multiple protection and control functions and can be programed to perform extensive and complex logical operations. They capture and store event and oscillographic fault records, can calculate and report a fault location, and have the ability to be remotely interrogated by maintenance personnel saving time and improving safety by eliminating the need to travel to the substation.

Microprocessor devices have integrating further into the SCADA systems becoming Ethernet capable devices resulting in less copper wiring between protection schemes and the SCADA system. Additionally, with the introduction of the IEC61850 standard of inter-device Ethernet communications, a further reduction in copper wiring between protection relays and the associated design and installation processes will provide future cost savings.

5.11 Makes and models

There are 166 discrete models and 28 different manufacturers of protection and control relays installed within the transmission system. Several unique installations present a maintenance issue, since lack of familiarity with these relays increases the effort required to maintain the protection and control schemes. Within each model there are also variations in order code that also creates complexity around spares management and maintenance activities, specifically with microprocessor based relays where setting file compatibility through software versions is an issue.

5.11.1 Transformer

TasNetworks has recently revised the transformer protection and control standards and as such revised the design template standardising on the Siemens 7UT86 and GE Multilin T60 models as the ‘A’ and ‘B’ protection relays. With the increase in processing power of these modern microprocessor relays it was found that the MCAG34 electromechanical relay and the two D30 bay control relays could be removed from the standard network transformer protection scheme, and the designs for both supply and network transformer protection schemes could also be aligned to introduce additional standardisation. A change to the AVR has been introduced from the Reyrolle MicroTAPP to the Eberle Reg-D due to the MicroTAPP’s inability to integrate appropriately with the SCADA system and Reyrolle’s discontinuation of the model.

5.11.2 Transmission line

The most recent transmission line protection and control schemes have used the Schneider P544 and the GE Multilin L90 models as the ‘A’ and ‘B’ relays due to their ability to accommodate multiple current inputs as required for circuit breaker and a half or double breaker switch yard configurations. The bay control relay has been selected as the GE Multilin C60 for its ease of configuration and maintenance.

5.11.3 Bus bar

TasNetworks use the GE Multilin B90 or the Schneider P740 model as the standard low impedance EHV busbar protection relay depending on the number of zones of the substation busbar arrangement. At sites that require duplication, where the B90 is not able to accommodate the number of zones, the Siemens 7SS52 model has been used to compliment the P740 model. For high impedance busbar protection schemes, the standard relay model is the Schneider P143 and where duplication is required, the Alstom MCAG34 is also used. The standard EHV bus coupler protection and control scheme utilises the GE Multilin D30 as protection with integrated bay control.

5.11.4 Capacitor bank

TasNetworks have not standardised on capacitor bank protection and control relay models but the most recent (2010) EHV capacitor bank installation utilised the ABB REF543, Schneider P143, and Stike Technologies RLC models. The scheme also utilised the ABB E213 SwitchSync to provide the point-on-wave circuit breaker closing function. The standard models used for HV capacitor bank protection and control schemes include the ABB SPAJ160C and the Schneider P143 to provide the protection functions and the GE Multilin F35 to provide the control functions including the automatic switching feature.

5.11.5 HV

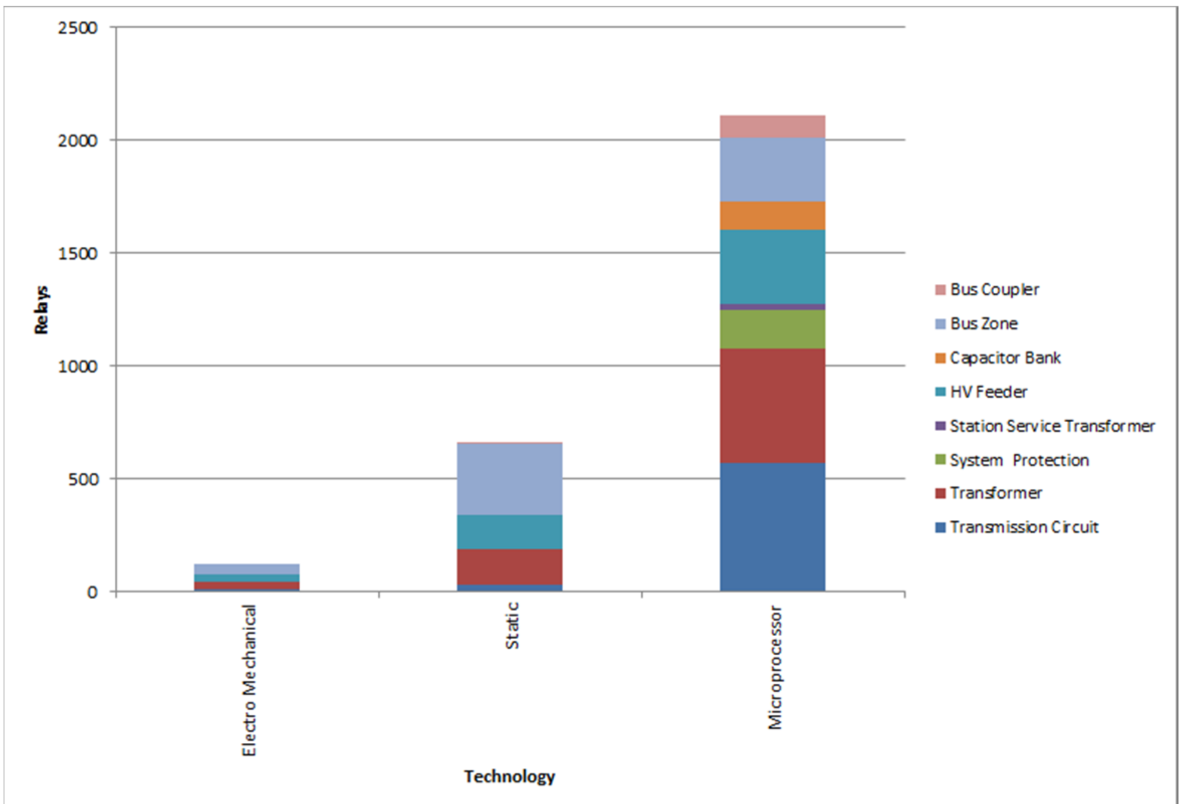
The most commonly used HV feeder, incomer and bus coupler protection and control relay is the Areva P143 although TasNetworks have recently decided to standardise on the Siemens 7SJ82 model due to the need to report a reactance to fault for use in the DINIS software and the reliability issues of the Ethernet connection from the P143. The high impedance busbar protection relay used on the latest HV switchboard installation was the Alstom MCAG34; however, similar to the high impedance EHV busbar protection schemes, the preferred model shall be the Schneider P143. For most existing HV switchboard busbar protection replacements, overcurrent blocking functions are re-instated due to a lack of available CT cores for high impedance busbar protection.

5.11.6 UFLS

TasNetworks have a standard panel design template for the UFLS protection that utilises the Areva P941 frequency relay as the main and the Siemens 7RW600 frequency relay as the check. Since the schemes were introduced state-wide in 2006, the standard has changed and the frequency protection will be incorporated within the HV feeder protection relay. Only larger load shedding schemes such as those at major industrial installations will require a stand-alone protection panel.

shows the quantity of relays of each technology type for each protection and control scheme type.

Figure 2 Transmission protection and control relay technology



5.12 Condition assessment

The condition of the transmission protection and control equipment is assessed for each relay model using the failure rate for the specific model, availability of manufacturer support, quantity and health of spares, and inherent design issues.

The failure rate for the model is calculated using the number of failures recorded per year over the last five years per relay currently in service. By using the failures per relay of a fleet of a model the rate is normalised so that models with higher populations are not singled out as poor performers in relation to models with lower populations which is a common misconception by maintenance personnel.

Figure 3 shows the failures recorded against specific relays for each protection and control scheme category over the past five years. It is assumed that not all failures are attributed to a specific relay, however with a new asset management system and associated processes and training planned to be implemented by 2019, it is anticipated that all asset failures will be recorded against the correct asset and more accurate condition monitoring will be undertaken.

Protection and control relay manufacturers offer relays of a model for an undetermined period of time because as technology develops, new models are created and the older models become obsolete. For a period of time after the cessation of an existing model, the manufacturer provides support through repair services and firmware development. However the manufacturer has to concentrate their efforts on the newer models so once full product support ceases, network asset managers have to plan the replacement of obsolete models before spares deplete and further firmware issues begin to develop.

Figure 4 shows the quantity of relays with their associated manufacturer support.

Figure 3 Transmission protection and control relay failures

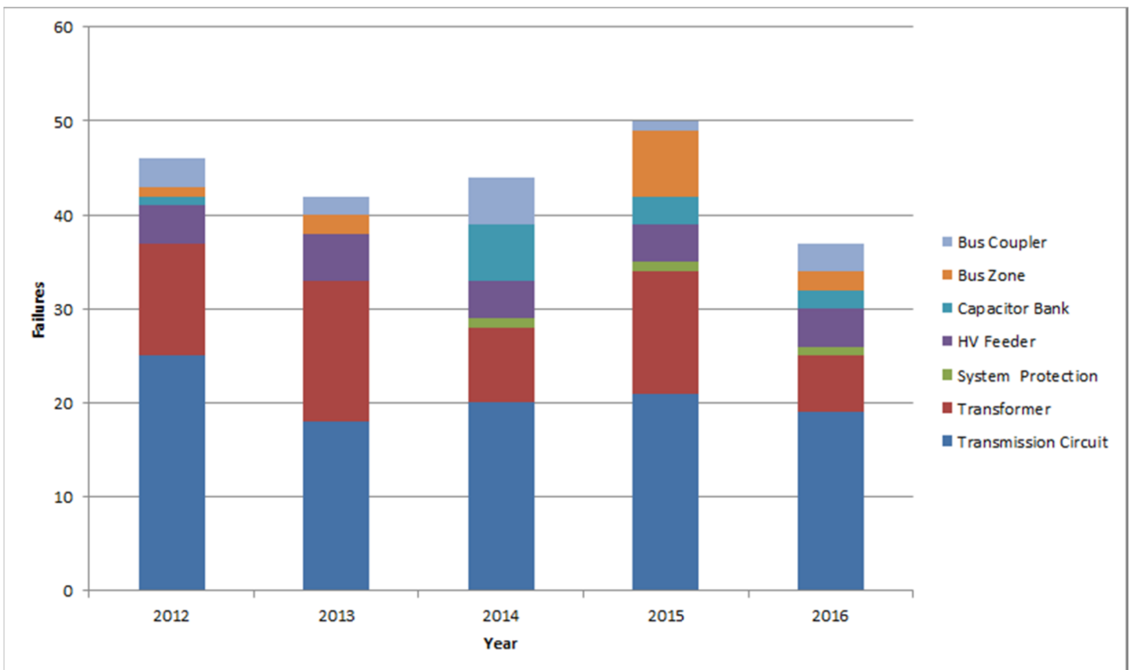
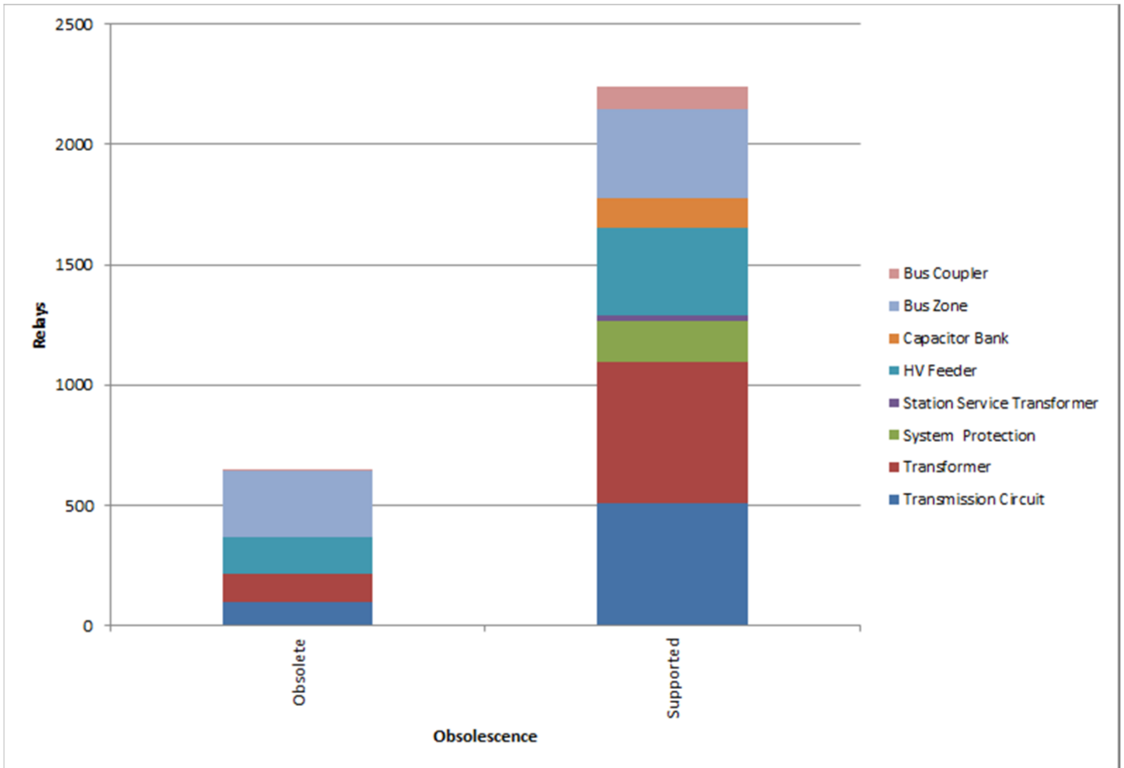


Figure 4 Transmission protection and control relay obsolescence



5.12.1 Condition rating criteria

The criteria used to define a relay model in poor condition are as follows:

(a) An electromechanical or static model with a MTBF less than 3 years;

(b) An obsolete model that will deplete all spares within 5 years;

(c) An obsolete model that has no spares; and

(d) An obsolete model with a design issue that affects the relays reliability.

The criteria used to define a relay model in average condition are as follows:

(a) An obsolete model with only one spare;

(b) An obsolete model that will deplete all spares within 5 to 10 years;

(c) An obsolete static model where the spares have an average age exceeding 30 years; and

(d) A supported model with no spares.

A supported model with no spares is immediately referred to the Protection and Control maintenance team to order the sufficient quantity of spares to align with the spares policy of this asset management plan.

Examples of design issues include an identified failure trend within a model that results in spurious tripping or functions that cannot be performed by a model that are now required due to changes within the transmission system such as inverse time overcurrent characteristics.

Figure 5 shows the quantity of relays for each scheme type and their condition rating demonstrating the overall condition of the protection and control assets, and

Figure 6 shows the quantity of relays for each model assessed with an average or poor condition.

In general, the condition of TasNetworks' transmission protection and control assets is good with the majority of relays being modern microprocessor technology still supported by their manufacturer and providing the self-supervision functionality.

Figure 5 Transmission protection and control relay condition rating

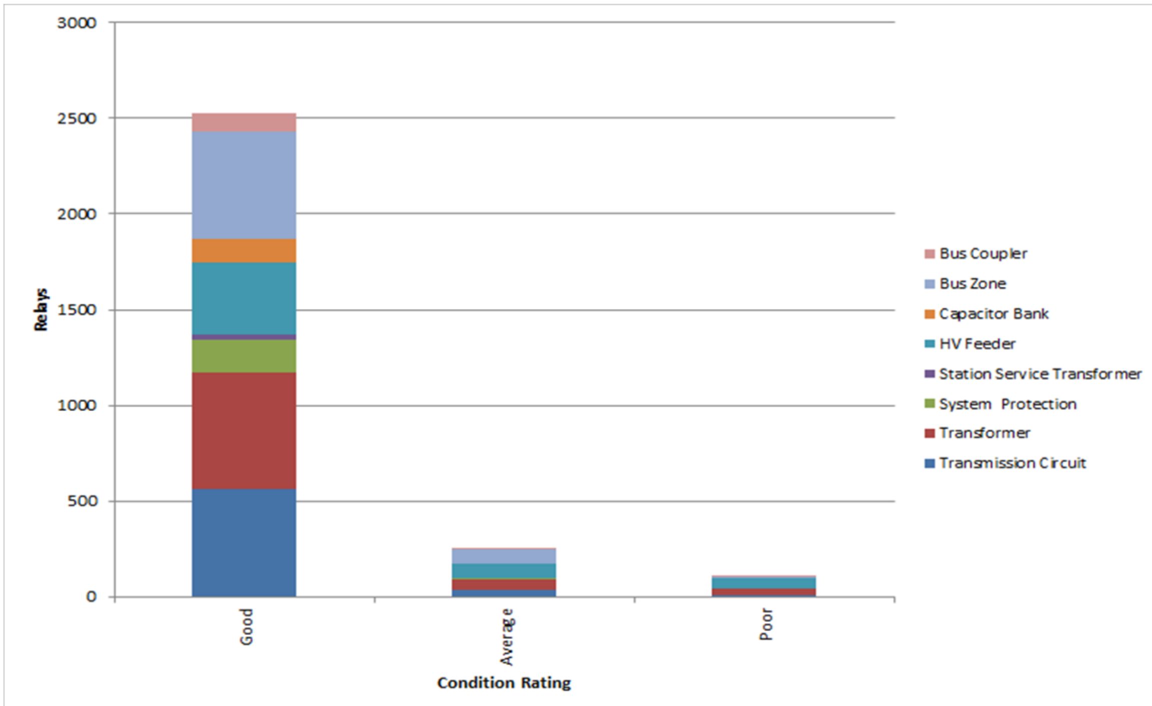
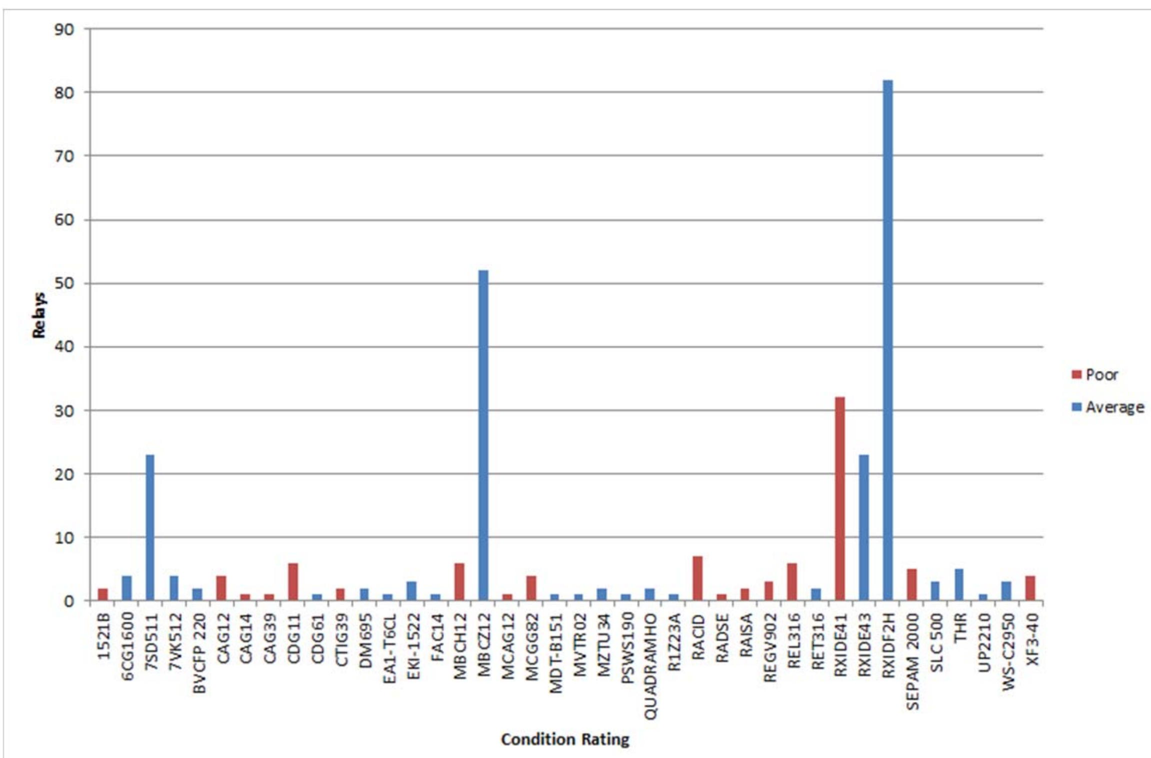


Figure 6 Relay models with average or poor condition rating



5.12.2 Online condition monitoring

Investigations will be carried out to assess the viability of additional online condition monitoring parameters for protection and control assets. The traditional online monitoring includes monitoring watchdog alarms SCADA communications and protection communications via the SCADA system. In addition to these parameters and where the relay is capable, internal temperatures and power supply voltages shall also be monitored with set point alarms to be generated via the SCADA system if measured points drift outside predetermined parameters. It is recommended to trial the additional online monitoring at five sites to collect data to see if any correlation can be made between temperature or power supply drift and relay failures can be obtained.

6 Standard of service

6.1 Technical standards

TasNetworks manage a suite of technical standards for each asset category. There are 11 technical standards applicable to the transmission protection and control schemes which are listed at the end of this document.

TasNetworks also manage a suit of standard protection and control panel design standard drawings. These drawings have been developed for the 110 kV and 220 kV transmission line protection and control schemes, the network transformer protection and control scheme and the UFLS protection scheme. Section 8.1.7 provides more detail on equipment, design, setting and testing standardisation.

Below is a list of technical standards relating to protection and control Transmission assets

- R245707 Protection and Control of Supply Transformers Standard;
- R246242 Protection and Control of Network Transformers Standard;
- R246427 Protection of Transmission Lines Standard;
- R246414 Protection of EHV Busbars Standard;
- R245701 Protection and Control of EHV Capacitor Banks Standard;
- R245703 Protection and Control of HV Capacitor Banks Standard;
- R246419 Protection of HV Busbars and Feeders Standard;
- R246444 Secondary Systems – General Requirements Standard;
- R246497 Testing, Commissioning and Training Standard; and
- R244782 Secondary Equipment Testing Standard.

6.2 Performance objectives

Protection is required to be secure and reliable to ensure that primary system faults are isolated quickly ensuring the least disturbance and instability to the remaining network. It is important that protection co-ordinates appropriately with adjacent protection schemes to only disconnect the faulted parts of the network and optimise transmission and distribution circuit availability. The timeframe to restore failed protection services often has a high impact on primary equipment availability and system capacity.

Under the requirements of clause 6A.7.4 of the NER, TasNetworks participates in the AER's service target performance incentive scheme (STPIS).

The components of the scheme are monitored annually and include:

(a) Average circuit outage rate;

(b) Loss of supply event frequency;

(c) Average outage duration; and

(d) Correct operation of equipment.

Components (c) and (d) have been included in the STPIS since July 2014 and at present do not impact on performance bonus/penalty payments but are an important measure of asset management.

Full details of the STPIS and associated performance targets can be found on the AER's website in the 'Electricity transmission network service provider's service target performance incentive scheme (December 2012)' literature.

TasNetworks also has a performance incentive scheme in place with Hydro Tasmania for connection assets between the two companies under the connection and network service agreement (CANS 2). The scheme includes connection asset availability and is described in more detail in the CANS 2 connection agreement.

6.3 Key performance indicators

TasNetworks monitors protection performance for transmission system outages through the transmission system incident reporting process. Where possible that the cause of the incident can be associated with the incorrect operation of the protection scheme, the appropriate protection relay is attributed to the incident with accompanying metadata to allow for asset level reporting. The incident is subjected to a detailed investigation that establishes the root cause of the fault outage with remedial actions assigned to reduce the likelihood of reoccurrence.

For protection failures that do not initiate a transmission system outage event, TasNetworks maintains defect and corrective maintenance records within the asset management system that provides performance and trending information for all protection and control relay models.

6.3.1 Benchmarking

TasNetworks participates in various formal benchmarking forums with the aim to benchmark asset management practices against international and national transmission companies. Key benchmarking forums include:

(a) International Transmission Operations & Maintenance Study (ITOMS);

(b) The Australian Energy Regulator's regulatory information notice (RIN); and

(c) Transmission survey, which provides information to the Electricity Supply Association of Australia (ESAA) for its annual Electricity Gas Australia report.

In addition, TasNetworks works closely with transmission companies in other key industry forums, such as CIGRE (International Council on Large Electric Systems), to compare asset management practices and performance.

6.3.1.1 ITOMS

The ITOMS provides a means to benchmark performance (maintenance cost and service levels) between related utilities from around the world. The benchmarking exercise combines all protection, SCADA and communications assets into one distinct category. Further details relating to ITOMS is provided in the ITOMS reports which are held by TasNetworks' Asset Performance team.

6.3.1.2 RIN

As a result of changes to the NER in November 2012, the AER serve a RIN to all Australian Transmission Network Service Providers (TNSP) and Distribution Network Service Providers (DNSP) to assist in the determination of their revenue proposal. The RIN data provides benchmarking information across TNSPs and DNSPs and is conducted annually to assess network performance and efficiency trends.

7 Associated risk

7.1 Associated risk

TasNetworks has developed a Risk Management Framework for the purposes of

- Demonstrating the commitment and approach to the management of risk – how it is integrated with existing business practices and processes and ensure risk management is not viewed or practiced as an isolated activity;
- Setting a consistent and structured approach for the management of all types of risk; and
- Providing an overview on how to apply the risk management process.

Assessment of the risks associated with the Protection and Control equipment has been undertaken in accordance with the Risk Management Framework. The risk assessment involves:

- Identification of the individual risks including how and when they might occur;
- Risk analysis of the effectiveness of the existing controls, the potential consequences from the risk event and the likelihood of these consequences occurring to arrive at the overall level of risk; and
- Risk evaluation where risks are prioritised based on their ratings and whether the risk can be treated) or managed at the current level.

The likelihood and consequence of risk events occurred are assessed using the following risk rating matrix in Figure 7:

Figure 7 Risk ranking matrix

		CONSEQUENCE				
LIKELIHOOD		1 NEGLIGIBLE	2 MINOR	3 MODERATE	4 MAJOR	5 SEVERE
• ≥ 99% probability • Impact occurring now • Could occur within "days to weeks"	5 ALMOST CERTAIN	MEDIUM	MEDIUM	HIGH	VERY HIGH	VERY HIGH
• 50% - 98% probability • Balance of probability will occur • Could occur within "weeks to months"	4 LIKELY	LOW	MEDIUM	HIGH	HIGH	VERY HIGH
• 20% - 49% probability • May occur shortly but a distinct probability it won't • Could occur within "months to years"	3 POSSIBLE	LOW	LOW	MEDIUM	HIGH	HIGH
• 1% - 19% probability • May occur but not anticipated • Could occur in "years to decades"	2 UNLIKELY	LOW	LOW	MEDIUM	MEDIUM	HIGH
• ≤1% probability • Occurrence requires exceptional circumstances • Only occur as a "100 year event"	1 RARE	LOW	LOW	LOW	MEDIUM	MEDIUM

The Risk Management Framework requires that each risk event is assessed against all of the following consequence categories:

- Safety and People
- Financial
- Customer
- Regulatory Compliance
- Network Performance
- Reputation
- Environment and Community

This asset management plan describes the major risks associated with SCADA and automation equipment assets and the current or proposed treatment plans.

7.2 Asset risks

The risk from transmission protection and control relay failure is assessed in accordance with TasNetworks' Corporate Risk Management Framework using the condition information for each relay model to determine the likelihood and consequences of failure.

The likelihood of failure is derived from the current failure rate of the model by converting the failure rate to a mean time between failures (MTBF). In accordance with the Corporate Risk

Management Framework, a MTBF between 10 and 100 years gives a likelihood of ‘rare’, an MTBF between 1 and 10 years is ‘possible’, and a MTBF between 0 and 1 year is classified as ‘unlikely’.

The main consequence associated with transmission protection and control assets arises when manufacturer support has ceased and dedicated spares have fully depleted. For this situation, the rectification of a failed relay becomes an unplanned refurbishment by installing a different model of relay in place of the failed relay which involves redesign and re-commissioning of the protection and control scheme as emergency work. These unplanned costs are not included in normal operational or capital budgets but tend to have a negligible effect on corporate finances; however, the flow on effect on protection and control resources can have a more significant effect on the delivery of the normal program of work. This emergency work can also leave the protection and control scheme in a precarious state as most new relay installations require significant design work to be undertaken by experienced protection and control engineers and require significant planning and testing to ensure a high quality and reliable installation.

Another consequence associated with protection relay failure comes from incorrect operation resulting in the disconnection of healthy circuits. This usually occurs due to a relays internal component breaking down or more commonly due to calibration drift from aging mechanical or electronic components. For this consequence to be significant, the circuit must be supplying customer load directly and not form part of a firm customer supply.

Most of TasNetworks’ transmission protection and control schemes have multiple relays providing redundancy within the scheme; hence if one relay fails to operate, a system fault will normally be cleared by the duplicated healthy relay. This is not always the case, especially for TasNetworks’ HV feeder and most EHV busbar protection schemes, where duplicate relays are not provided. The consequence in this case is to the safety of the public in the vicinity of the HV distribution network or personnel working in TasNetworks EHV switchyards. Additionally, on a lot of overhead HV feeders, fast fault clearance is essential to minimise the risk of bushfire starts which can present a catastrophic consequence to some communities.

Table 2 shows the transmission protection and control schemes that have associated relays presently identified with poor or average condition that presents a risk to the operation of the transmission and distribution networks.

Table 2 Transmission protection and control present risk assessment

Location	Scheme type	Schemes	Likelihood	Consequences	Risk rating
Boyer	HV Feeder	7	Unlikely	Negligible financial Moderate customer	Medium
	Transformer	4	Unlikely	Negligible financial Moderate customer	Medium
	Transformer	1	Rare	Negligible financial Negligible customer	Low
	Busbar	1	Rare	Negligible financial Moderate customer	Low
Bridgewater	Transmission Line	1	Unlikely	Negligible financial	Low
Burnie	Busbar	1	Rare	Negligible financial Negligible customer	Low
Chapel Street	Busbar	2	Rare	Negligible financial	Low

Location	Scheme type	Schemes	Likelihood	Consequences	Risk rating
				Moderate customer	
	HV Feeder	23	Rare	Negligible financial Negligible customer	Low
	Transformer	2	Rare	Negligible financial	Low
	Transmission Line	1	Rare	Negligible financial	Low
Creek Road	Transformer	3	Rare	Negligible financial	Low
Derwent Bridge	Transformer	1	Rare	Negligible financial Negligible customer	Low
Emu Bay	Busbar	1	Rare	Negligible financial Negligible customer	Low
	HV Feeder	5	Rare	Negligible financial Negligible customer Severe safety	Medium
Farrell	Transmission Line	2	Unlikely	Negligible financial Negligible customer	Low
	Transmission Line	1	Rare	Negligible financial Moderate customer	Low
	Transformer	2	Rare	Negligible financial	Low
George Town	Transmission Line	2	Rare	Negligible financial Moderate customer	Low
	Transmission Line	1	Unlikely	Negligible financial	Low
Gordon	Bus Coupler	2	Rare	Negligible financial	Low
	Transformer	1	Rare	Negligible financial Negligible customer	Low
Hadspen	Bus Coupler	2	Rare	Negligible financial	Low
	Transformer	2	Rare	Negligible financial	Low
	Transmission Line	6	Unlikely	Negligible financial	Low
Liapootah	Transmission Line	1	Unlikely	Negligible financial Negligible customer	Low
Lindisfarne	Busbar	1	Rare	Negligible financial Negligible customer	Low
	Transmission Line	3	Unlikely	Negligible financial	Low
North Hobart	HV Feeder	12	Rare	Negligible financial Negligible customer Severe safety	Medium
	Transformer	2	Rare	Negligible financial	Low
Norwood	Transmission Line	2	Unlikely	Negligible financial	Low
Palmerston	Transmission Line	3	Unlikely	Negligible financial Negligible customer	Low
Que	Transformer	1	Rare	Negligible financial	Low

Location	Scheme type	Schemes	Likelihood	Consequences	Risk rating
				Negligible customer	
Risdon	Transmission Line	4	Unlikely	Negligible financial	Low
Rokeby	Transmission Line	2	Unlikely	Negligible financial	Low
Starwood	Transmission Line	1	Unlikely	Negligible financial	Low
Trevallyn	Busbar	1	Rare	Negligible financial Negligible customer	Low
	Transmission Line	2	Unlikely	Negligible financial	Low
Wayatinah Tee	Transmission Line	2	Unlikely	Negligible financial	Low

7.3 Summary of risks

The following table summarises the protection and control risks, their mitigation strategy and residual risk levels.

Table 3 Summary of risks

RISK IDENTIFICATION		RISK ANALYSIS				RISK MITIGATION	
Risk	**Detail**	**Likelihood**	**Consequence**	**Risk Rank**	**Category**	**Elimination or Mitigating Action(s)**	**Residual Risk Rank (if not eliminated)**
EHV Bus Bar protection failure	Failure of EHV Bus Bar protection results in injury or loss of life to staff and extensive damage to assets.	Rare	Moderate	Low	Customer	Planned replacement of EHV busbar protection schemes to ensure the continued reliable operation of the protection scheme to mitigate risks to an acceptable level.	Low
		Rare	Minor	Low	Network Performance		
		Rare	Severe	Medium	Safety		
		Unlikely	Moderate	Medium	Network Performance		
		Rare	Minor	Low	Environment		
		Rare	Minor	Low	Financial		
Transmission Line protection failure	Failure of EHV Transmission Line protection results loss of supply, possible injury to staff or customers, possible environmental and extensive damage to assets.	Possible	Moderate	Low	Customer	Planned replacement of Transmission Line protection schemes to ensure the continued reliable operation of the protection scheme to mitigate risks to an acceptable level.	Low
		Possible	Minor	Low	Network Performance		
		Rare	Severe	Medium	Safety		
		Rare	Moderate	Low	Network Performance		
		Rare	Minor	Low	Environment		
		Rare	Minor	Low	Financial		
Transformer protection failure		Possible	Moderate	Low	Customer	Planned replacement of Transformer protection schemes to ensure the continued reliable operation of the protection scheme to mitigate risks to an acceptable	Low
		Possible	Minor	Low	Network Performance		
		Rare	Severe	Medium	Safety		

RISK IDENTIFICATION		RISK ANALYSIS				RISK MITIGATION	
Risk	**Detail**	**Likelihood**	**Consequence**	**Risk Rank**	**Category**	**Elimination or Mitigating Action(s)**	**Residual Risk Rank (if not eliminated)**
		Rare	Moderate	Low	Network Performance	level.	
		Rare	Minor	Low	Environment		
		Rare	Minor	Low	Financial		
EHV Capacitor Bank protection failure		Possible	Moderate	Low	Customer	Planned replacement of EHV Capacitor Bank protection schemes to ensure the continued reliable operation of the protection scheme to mitigate risks to an acceptable level.	Low
		Possible	Minor	Low	Network Performance		
		Rare	Severe	Medium	Safety		
		Rare	Moderate	Low	Network Performance		
		Rare	Minor	Low	Environment		
		Rare	Minor	Low	Financial		
HV Feeder protection failure		Possible	Moderate	Low	Customer	Planned replacement of HV protection schemes to ensure the continued reliable operation of the protection scheme to mitigate risks to an acceptable level.	Low
		Possible	Minor	Low	Network Performance		
		Rare	Severe	Medium	Safety		
		Rare	Moderate	Low	Network Performance		
		Rare	Minor	Low	Environment		
		Rare	Minor	Low	Financial		

8 Management strategies and plans

8.1 Management strategies

The asset management strategies for transmission protection and control schemes are described in the following sections.

8.1.1 Routine maintenance strategy

To determine if a protection relay is functioning correctly the protection scheme is routinely tested by injecting current and voltage into the relay to simulate fault conditions and measuring the relays operation to assess its health. Some basic operating parameters to be tested include the current and voltage magnitudes and the operation time delay. The operational parameters are checked against the applied settings to determine the health of the relay. Additionally the relay's settings are compared to the stored settings to ensure correct settings management processes are being applied.

TasNetworks' policy for routine testing of transmission protection is based on the following criteria:

(a) Schemes with relays that have self-supervision ability are sample tested at eight year intervals instead of the previous six year interval; and

(b) Schemes with relays that do not have self-supervision ability are tested at three year intervals.

TasNetworks is minimising the testing regimes for self-supervised relays. This strategy involves the re-allocation of maintenance resources to perform testing and asset acceptance of new installations rather than waiting for six years before conducting the first routine test. The outcomes of this strategy should include reduced maintenance costs, minimised human error faults, provide an increased understanding of new installations for TasNetworks testing resources and provide more efficient utilisation of project engineers as they will no longer be required for witness testing. TasNetworks is working towards a new approach to replace the current whole fleet testing strategy. The new strategy will incorporate statistical testing and utilise the statistical model of 90% confidence with a confidence interval of 5%.This statistical model will drive the number of units of the fleet of a particular model that shall be tested within the eight year period. The sample should be spread across as many substations and regions as possible. Each eight year test cycle should test different relays in the fleet concentrating on the oldest devices in the fleet as the highest priority. This strategy shall be incorporated in the SAP tool to assist in allocating the annual relays for test.

Successful protection operations caused by primary system faults shall be included in the sample tested for that model in the current test period.

Routine maintenance of the NCSPS and FCSPS system protection schemes requires tests to be undertaken by the associated participants as per schedule 5 of the SPS participation deed.

The method for testing at Hydro Tasmania's generator includes:

(a) simulated receipt by the participants remote assets of an interrupt signal; and

(b) timing tests for:

   (i) trip signal receipt within 10 ms (main and duplicate);

  (ii) circuit breaker opening within 200 ms (main and duplicate); and
  (iii) governor solenoid tripping within 15 seconds (main and duplicate).

(c) Tests are to be performed within 42 months following the later of:
  (i) the date of the most recent tests; or
  (ii) the date of the most recent successful provision of an interruption service.

The method for testing at participating industrial loads includes:

(a) simulated receipt by the participants remote assets of an interrupt signal; and

(b) timing tests for:
  (i) circuit breaker opening within 200 ms (main and duplicate); and
  (ii) Participant's circuit breaker trip status to be received by TasNetworks. If any circuit breaker status indication fails, it is required to carry out the test within 1 month of the interruption service.

(c) Tests are to be performed within 36 months following the later of:
  (i) the date of the most recent tests; or
  (ii) the date of the most recent successful provision of an interruption service.

8.1.2 Corrective maintenance strategy

Corrective maintenance of transmission protection and control relays is initiated by:

- relay failures found during routine maintenance testing;
- relay failures alarmed by self-supervision through the SCADA system;
- relay failures found during investigation of power system faults; and
- manufacturer product notices.

The process to rectify a failed relay is to remove the failed relay and replace it with an identical spare. The failed relay is then sent back to the manufacturer for repair because TasNetworks do not have the capability to perform repairs on such complex equipment.

TasNetworks manage after-hours availability rosters in the north and south of the state to ensure that corrective maintenance issues are rectified as quickly as possible.

8.1.3 Refurbishment and replacement strategy

The term refurbishment, as applied to protection schemes, refers to the renewal of an individual relay of the protection and control scheme which is mostly the case for corrective maintenance that is required for a failed relay that has no dedicated spare. This requires replacing the failed relay with a different model of relay, which includes modification to or the creation of new settings and scheme re-commissioning. This work currently occurs under maintenance processes and does not go through the quality controls of a planned renewal project which can have an effect on future operations of the protection scheme.

The asset replacement strategy targets specific models of relay that present a risk to the operation of the transmission system. By replacing obsolete relays with standardised models, benefits are achieved in technological advancement, maintenance processes and spares management.

Due to the relatively short lifespan of protection and control relays and the volatility of the associated technology, planning the future replacement program is difficult to predict and in order to prepare for the future replacements, forward projections of potential asset failures and obsolescence is used.

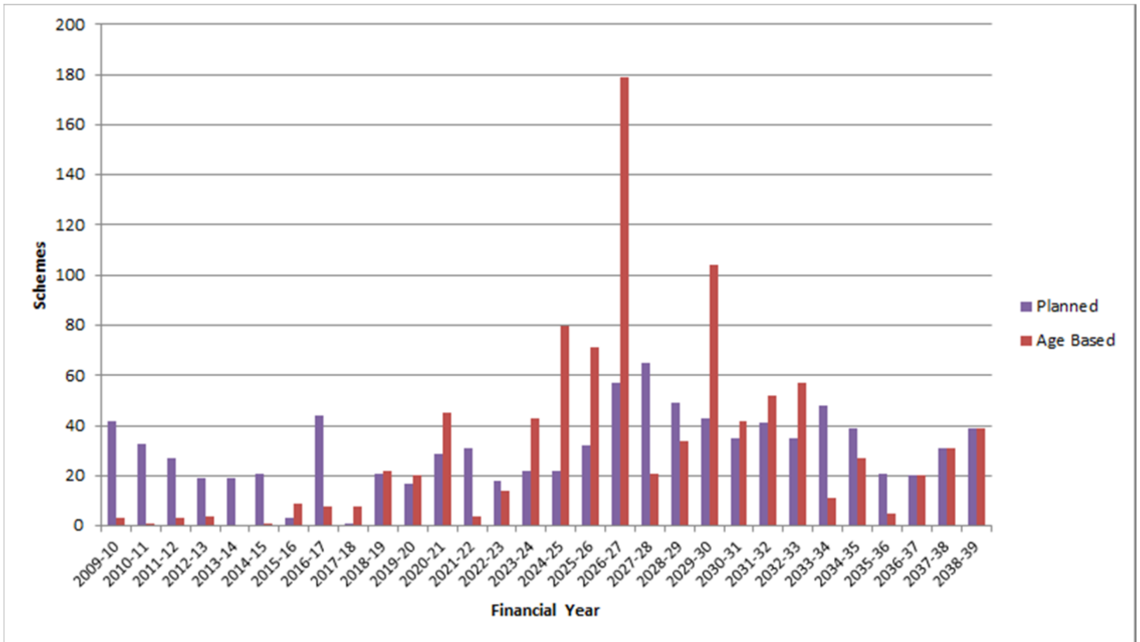
Where 19” Rittal (or similar) swing frame panels are installed the replacement strategy is to retain the protection panel, internal wiring, terminal blocks and external control cables for the life of the primary asset being protected. In this case the protection and control relays can be refurbished in situ with minimal disturbance of the control cabling. A refurbishment strategy will be required for each type protection or control device that will be managed under this strategy. The strategy will be required to address the following:

1) Internal wiring modifications and associated drawing mark-ups; and
2) Protection, control and SCADA setting requirements.

TasNetworks’ standard for implementing UFLS at sites where individual feeder distribution loads are shed has changed. The strategy for implementing under frequency tripping of smaller distribution (residential) load will be to implement the under frequency function in the individual HV feeder protection relay. This will be a more efficient approach as the feeder protection relays are capable of performing these functions and with the tripping of smaller loads, the frequency trip will not require a checking function. As dedicated UFLS protection panels become due for renewal, the strategy will be to incorporate the UFLS functionality into the existing HV feeder protection relay. Only larger UFLS installations that trip large blocks of industrial load will be renewed with a standard UFLS panel installation.

Due to past protection and control replacement programs and substation redevelopment projects, it is predicted that there will be a significant escalation in protection scheme renewals between 2024 to 2026 and 2029 to 2030. This increase in replacement projects will have an impact on resources within the specialist area of protection design and commissioning. For this reason, a levelling process has been undertaken by moving some of the age based replacements forward across the next two revenue periods. This levelling process is demonstrated in Figure 8 below. The age based replacement is assumed to occur at 20 years of age, whilst the economic life of a protection relay is 15 years. Hence all assets brought forward will be fully depreciated before the planned replacement occurs. The “Bow-Wave” replacement effect is common for a lot of asset categories, however, that is mainly an issue due to economic impacts especially for the more expensive primary assets. The concern for protection scheme replacements is the impact on specialist resources. The risk from high volumes of protection replacements is poor quality installations leading to poor reliability throughout the life of the new assets. The levelling has also taken into account transmission line ends of interconnecting substations so as to introduce project delivery efficiencies and optimisation of network outages.

Figure 8 Future protection scheme replacement scenarios



8.1.4 Network augmentation strategy

TasNetworks' requirements for developing the transmission system are principally driven by five elements:

- Demand forecasts;
- New customer connection requests;
- New generation requests;
- Network performance requirements; and
- National electricity rules (NER) compliance.

The implementation of new protection and control schemes is primarily driven by all five of these elements.

8.1.5 Refurbishment, replacement and augmentation testing strategy

TasNetworks strategy for refurbishment, replacement and augmentation testing shall change from utilising contract testers to utilising TasNetworks resources. The main driver for this change is to ensure the installation and commissioning work performed by contractors conforms to the TasNetworks standards. With the current practice routine testing carried out by TasNetworks resources is not scheduled for at least six years after the installation, the defects liability period expires prior to this testing and historically most defects are found at the first scheduled preventative maintenance test. By utilising TasNetworks testing resources to perform the acceptance tests, defects can be identified and remedied during the commission and defects liability period ensuring the schemes function correctly from the day they are commissioned.

8.1.6 Settings management strategy

TasNetworks utilise the Digsilent Power Factory software for protection coordination modelling and the Digsilent StationWare software for storage of all hard and soft copies of protection and control relay settings.

Details of the settings management process can be found in the Device Settings and Configuration Management Procedure for CAPEX Projects document – issue 3.0 August 2013.

8.1.7 Standardisation

TasNetworks has standardised on a smaller number of relay models to reduce the overheads associated with maintaining a diverse range of equipment but currently do not have period supply contracts for the protection and control. A suit of standard panel design drawings have been developed around the currently selected models of relay. The standard scheme designs must not be modified until a review of the associated technical standard is performed which is undertaken on a 60 month cycle. For standardisation of protection and control panels to be successful, the designs must integrate with all primary designs. Therefore the primary designs must also be standardised. Standard panels shall be developed for all protection and control applications, including but not limited to the list below:

(a) Transmission line (to include synchrophasor);

(b) Transformer;

(c) Bus bar;

(d) Bus coupler

(e) Capacitor bank;

(f) UFLS; and

(g) SPS.

8.1.7.1 Standard Templates

Each standard panel design shall be accompanied with standard templates for each implementation including the following:

(a) Standard drawings;

(b) Standard setting files;

(c) Standard ITPs, OMICRON test plans and associated documentation;

(d) Design Manuals;

(e) Training Manuals;

(f) Construction and maintenance manuals; and

(g) OEM documentation.

8.1.7.2 Standard Modules

To assist in capital works delivery standard modules shall be developed for primary and secondary assets. This will tie standard protection panels and templates to standard primary designs. These designs can then be costed, and become standard building blocks to be used by the business. The time and effort required to develop detailed functional and technical specifications for augmentation and replacement works shall be reduced as standard designs and documentation will be utilised. The cost and time to deliver detailed estimates will also be reduced as costs shall already be quantified.

8.1.7.3 Standard Panel Manufacture

TasNetworks shall administer the local manufacture of standard panels to reduce costs, improve consistency and allow period contracts to be formed with relay vendors. The added benefit of the period contracts is to form closer relationships and gain improved vendor support. The amount of REPEX work between 2017 and 2029 has been quantified, panel quantities can be assessed and manufactured in batches to reduce costs. The added benefit is TasNetworks will be a good corporate citizen by employing local labour to manufacture the panels.

Once manufactured the panels can be acceptance tested (FAT) in the P&C Lab using the standard settings template reducing the amount of SAT testing required on site, as only the site specific settings and equipment connections will require testing.

These panels can be free issued as part of project work reducing the cost and times associated with design and manufacturing. The added benefit assisting in the delivery of capital works projects.

8.1.8 Technology implementation strategy

To reduce the risk of introducing new technologies that fail in service, creating one off designs and stranded assets a strategic change is required. This change includes comprehensive laboratory testing of any new technology prior to installing it on the network or incorporating it into a standard design.

TasNetworks staff shall be utilised to perform research and development with assistance from outside resources when required. The protection and control laboratory is ideally suited for carrying out conformance testing of new equipment. The following criteria should be implemented for the introduction on new equipment:

1) Business need clearly identified;
2) Conforms to asset strategy; and
3) ITP developed, to test all parameters for suitability (hardware, environmental, software).

Once this testing is complete a HAZOP shall be completed prior to modifying standards or creating standard designs and templates.

8.1.8.1 IEC 61850

In 2013, a strategy paper for the implementation of IEC61850 into TasNetworks' EHV substations was developed. The strategy identified a potential pilot project to install an IEC61850 station bus and describes the pilot project. The risks associated with this strategy include:

1) the reliance on contractors to deliver R&D, templates and designs;
2) risks of delivering project on time and on budget;
3) TasNetworks not being technically ready to scope, manage or check the project; and
4) TasNetworks being unable to maintain or augment the equipment.

To ensure the successful implementation of IEC61850 station and process bus technologies the following changes have been made to the strategy paper. Utilising internal resources for all activities relating to the Research and Development (R&D) and initial implementation, will provide ownership of the process resulting in greater understanding and acceptance by staff. Extensive R&D to include:

1) IEC-61850 TasNetworks Standard;
2) standard designs;
3) standard configuration tools;
4) standard templated settings;
5) standard ITPs;
6) development of installation and maintenance manuals;
7) training for internal and external resources; and
8) change management processes and documentation.

8.1.8.2 Special Protection Schemes

For system protection schemes such as the NCSPS, FCSPS and anti-islanding protection where a centralised software program is required to analyse the state of the network, Synchrophasor technology shall be utilised. The strategy is to install Synchrophasor capable protection relays in major transmission lines and network transformer protection schemes, then concentrating the Synchrophasor data within the substation SCADA Panel utilising a Phasor Data Concentrator (PDC) for bulk upload to the centralised control centre. The Synchrophasor data is accurately time synchronised which enables comparison of voltage and current phasors at discrete sections of the transmission network. Once new relays are installed in the main transmission substations and sufficient Synchrophasor data is available, the existing, stand-alone equipment used for system protection and monitoring can be decommissioned introducing efficiencies in the management of protection and control equipment.

Synchrophasor data can be used for many applications to assess and monitor the performance of the transmission network including analysing losses in transmission lines and recording system-wide disturbances in the network. Synchrophasor data is currently being used between Hadspen and Derby substations to detect an islanding condition in order to disconnect the Musselroe Wind Farm from the Derby load.

8.1.9 Disposal strategy

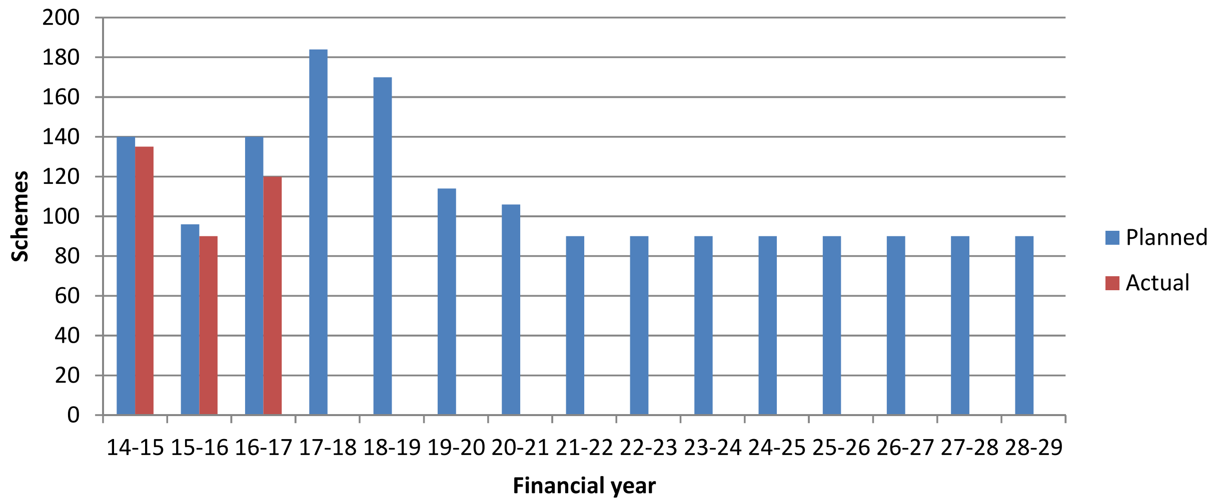
Transmission protection and control relays that are de-commissioned and removed from substation sites as part of capital replacement projects are disposed of by the project Contractor. Required assets are retained for system spares, as identified by project representatives from the Asset Engineering team.

8.2 Routine maintenance

Historically the TasNetworks transmission protection routine maintenance plan was developed and managed using a business-wide software tool known as Basix. Basix is linked to the asset and works register (WASP) and is programmed to automatically apply routine maintenance tasks using regimes set by the criteria described in this asset management plan. In 2018 SAP will replace BASIX as the routine maintenance planning tool.

From the information contained within the Basix works programming tool, the number of transmission protection schemes planned for routine maintenance spanning three revenue periods between 2014 and 2029 is shown in Figure 9. The figure also shows the actual number of schemes tested between July 2014 and June 2016 as extracted from the WASP works register.

Figure 9 2015 to 2029 protection scheme routine maintenance volumes

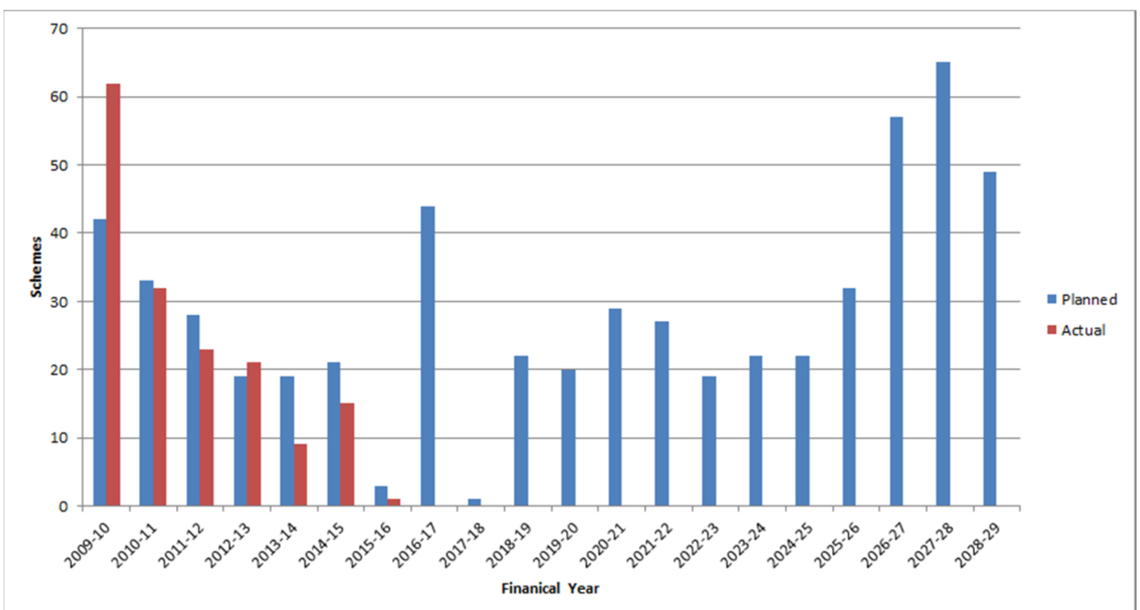


8.3 Replacement

The following figure shows the number of transmission protection schemes that are planned for replacement during the current revenue period and within the next two revenue periods. The figure also shows the number of transmission protection schemes that have been replaced within the current revenue period.

A complete listing of the planned transmission protection asset replacements is presented in Appendix A.

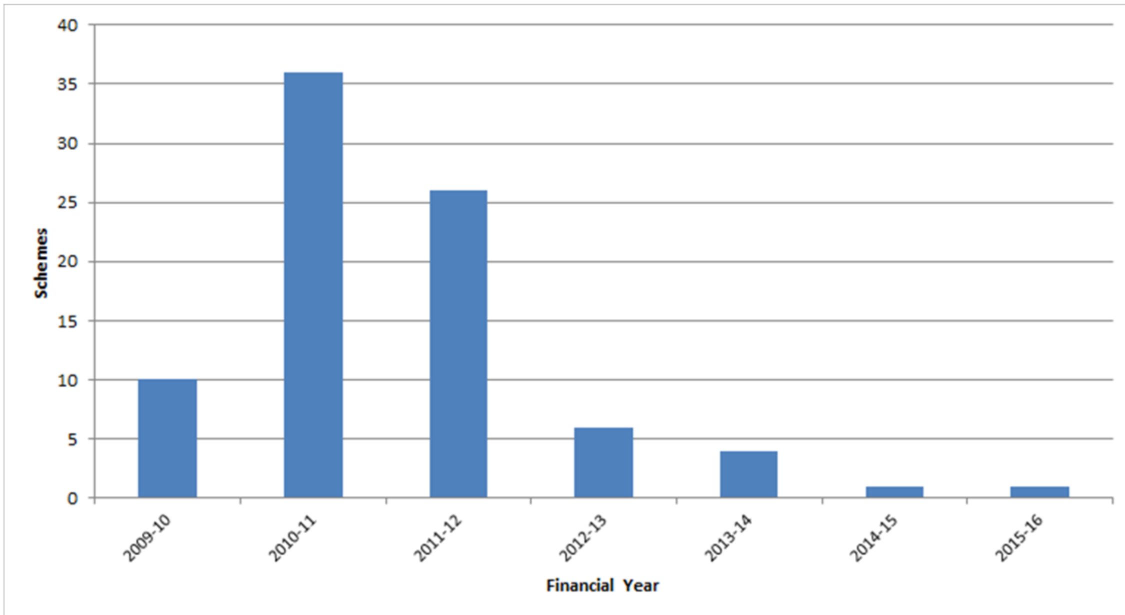
Figure 10 2009 to 2029 scheme replacement volumes



8.4 Network augmentation

The following table shows the number of new transmission protection and control schemes that have been installed within the past and current revenue periods 2009 to 2016. Most notably is the building of the Mornington and St Leonards Substations. Proposed network augmentation will not be shown within this asset management plan due to fluctuations in network demand, the volatility of new grid connections and the uncertainty of associated augmentation designs.

Figure 11 New transmission protection scheme installations



8.5 Investment evaluation

Investment evaluation is undertaken using TasNetworks' Investment Evaluation Summary template. The template includes:

- a brief description of the asset(s);
- a description of the issues and investment drivers;
- alignment with regulatory objectives;
- alignment with TasNetworks' corporate objectives;
- alignment with TasNetworks' corporate risks;
- impacts to customers;
- analysis of options to rectify the issues including operational and capital expenditures;
- a summary of NPV economic analysis for the identified options;
- the preferred option and why;
- the timing of the investment; and
- the expected outcomes and benefits.

8.6 Spares management

The management of spares is the responsibility of the Asset Engineering team. Deficiencies in spares holding are identified during the asset management plan development and where these models of protection relay are not obsolete, spares are ordered in alignment with the spares policy.

TasNetworks currently keep protection and control spares in two locations in alignment with the field services maintenance teams. The southern location is the Secondary Store Maria Street and the northern location is the Devonport office.

8.6.1 Spares policy

Sufficient spares are required to be maintained within the northern and southern regions to enable a replacement relay to be installed within the restoration times defined in the NEM operating procedures or associated connection agreements.

Spares are to be kept at an 8:1 in-service to spares ratio based on region (either north or south), to a maximum of three of each type per region.

Devices are to be kept as compete units, together with sufficient replacement parts to meet all credible contingencies.

If a project introduces a relay of unique design to the transmission system, or increases the quantity of a given relay type beyond the maximum 8:1 ratio, additional devices shall be purchased as a part of that project to enable the quantity of spares on hand to remain compliant with this policy.

9 Works program

9.1 Routine maintenance

The TasNetworks transmission protection routine maintenance program financial summary is collated via planned work tasks in the Basix works management software tool. The historical spend has been extracted from the financial system under the Protection and Control Preventive Maintenance activity centre (2240-1120).

9.2 Corrective maintenance

The transmission protection corrective maintenance budget is produced by the Protection and Control team in the Asset Engineering department of the Works and Services Delivery group.

9.3 Engineering support

Protection engineering support is provided by the Protection and Control team in the Asset Engineering department of the Works and Services Delivery group. The engineering support includes settings management and review, fault investigation and restoration support, standards and asset management plan review, technical design standard development and externally contracted support. The team provides support to capital projects through design review and acceptance, although this work is allocated to the capital budget. The engineering support forms part of the operational budget and is calculated by the Protection and Control team leader for each revenue period.

9.4 Renewals

9.4.1 Protection scheme renewals

The attached appendices show the number of schemes that have been renewed over the past 5 years or are planned for renewal within the next 10 years.

9.5 Budget and volumes

The forecast budget and volumes are contained in the Asset Management Plan two page summary document http://reclink/R0000863473.

10 Related documentation

The following documents have been used to either in the development of this management plan, or provide supporting information to it:

TSD-DI-809-0080-001	Network Transformer Protection Scheme Standard Panel Drawings
TSD-DI-809-0081-001	Transmission Line Protection Scheme Standard Panel Drawings
TSD-DI-809-0004-001	Under Frequency Load Shedding Scheme Standard Panel Drawings
	TasNetworks Risk Management Framework
D13/39576	Assessment of Proposed Regulatory Asset Lives
R611370	IEC61850 Implementation Strategy

Appendix A Transmission protection and control planned asset renewals

Table 4 2014 to 2019 planned protection and control scheme renewals

Location	Scheme Type	Primary Asset	Comments/Strategy
Burnie	Busbar	110kV	Complete scheme replacement
Boyer	Busbar	6.6kV	Switch house B scheme replacement
	Feeder	A3,B3,C3,D3,E3,F3,G3,H3	Complete scheme replacements
	Transformer	T1,T2,T7,T13,T14	Complete scheme replacements
Chapel Street	Busbar	110kV,220kV	Complete scheme replacements and duplicate 220kV
	Feeder	A2,B2,C2,D2,E2,F2,G2,H2,J2,K2,L2,M2,N2,P2,Q2,R2,S2,T2,U2,V2,W2,X2,Y2,Z2	Complete scheme replacements
	Transformer	T5,T6	Complete scheme replacements
Emu Bay	Busbar	11kV	Complete scheme replacement
	Feeder	C2,D2,F2,G2,H2	Complete scheme replacements
Farrell	Transmission Line	A1,B1,N1	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Gordon	Bus Coupler	A7,C7	Complete scheme replacements
	Busbar	220kV	Complete scheme replacement and duplicate
	Transformer	T6	Complete scheme replacement
Lindisfarne	Busbar	110kV	Complete scheme replacement
Liapootah	Busbar	220kV	Complete B scheme replacement
	Transmission Line	E1	Replace Siemens 7SD511 in situ with Wayatinah end
North Hobart	Busbar	11kV	Complete scheme replacement
	Feeder	B2,C2,D2,E2,F2,G2,M2,N2,P2,Q2,R2,S2	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Palmerston	Transmission Line	B1,C1,D1	Complete scheme replacements
Rosebery	Feeder	A2,B2,C2,D2	Replacement identified during detailed scoping
	Transformer	T1,T2,T4,T5	Complete scheme replacements
Trevallyn	Busbar	110kV	Complete scheme replacement
Wayatinah	Transmission Line	A1,B1	Complete scheme replacements

Table 5 2019 to 2024 planned protection and control scheme renewals

Location	Scheme Type	Primary Asset	Comments/Strategy
Avoca	Feeder	A2,B2,C2,D2	Complete scheme replacements
	Transformer	T1	Replace REF541 relay in situ
Bridgewater	Transmission Line	H1	Replace Siemens 7SD511 in situ
Burnie	Transmission Line	A1	Compete scheme replacement
Chapel Street	Transmission Line	K1	Replace Siemens 7SD511 in situ
Derby	Transmission Line	A1	Complete scheme replacement
Derwent Bridge	Transformer	T1	Replace existing relays with a basic installation
George Town	Feeder	B2,C2,D2,E2,F2,G2,K2,L2,M2,N2,P2,Q2	Complete scheme replacements
	Transmission Line	T1	Replace Siemens 7SD511 in situ
	Transformer	T4,T5	Replace REF541 relay in situ
Hadspen	Busbar	110 kV,220 kV	Complete scheme replacements
	Bus Coupler	BW7,D7	Complete scheme replacements
	Transmission Line	E1,G1,H1,J1,K1,N1,P1,Q1,T1,V1	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Lindisfarne	Transmission Line	A1,B1,C1	Replace Siemens 7SD511 in situ
Meadowbank	Feeder	A2,B2,C2	Complete scheme replacements
	Transformer	T4	Replace REF541 relay in situ
Mowbray	Transmission Line	B1	Complete scheme replacement
Norwood	Bus Coupler	A7	Complete scheme replacement
	Transmission Line	A1,B1,D1,E1	Complete scheme replacements
Palmerston	Busbar	110 kV, 220 kV	Complete scheme replacements
	Transmission Line	F1,K1,L1	Complete scheme replacements
Risdon	Busbar	11 kV,110 kV	Complete scheme replacements
	Bus Coupler	AB8,CD8,G7,H7	Complete scheme replacements
	Capacitor Bank	J6,K6	Complete scheme replacements
	Feeder	C3,D3,E3,F3,K3,Q3,R3,U3,V3	Complete scheme replacements
	Transmission Line	C1,F1,N1,Q1	Replace Siemens 7SD511 and 7VK512 in situ
	Transformer	T1,T2,T3	Complete scheme replacements
Scottsdale	Transmission Line	A1,B1	Complete scheme replacements
Sheffield	Busbar	110 kV,220 kV	Complete scheme replacements
	Transmission Line	F1,J1	Complete scheme replacements
Starwood	Transmission Line	A1	Replace Siemens 7SD511 in situ
Trevallyn	Bus Coupler	A8,B8,C8,D8	Complete scheme replacements
	Feeder	B2,C2,D2,E2,F2,G2,H2,J2,K2,L2,S2,T2,U2,V2,W2,X2,Y2	Complete scheme replacements

Location	Scheme Type	Primary Asset	Comments/Strategy
	Transmission Line	A1,B1,C1	Complete scheme replacements
	Transformer	T1,T2,T3	Complete scheme replacements

Table 6 2024 to 2029 planned protection and control scheme renewals

Location	Scheme Type	Primary Asset	Comments/Strategy
Boyer	Busbar	6.6 kV A Bus	Complete scheme replacement
Burnie	Bus Coupler	A8	Complete scheme replacement
	Capacitor Bank	F6	Complete scheme replacement
	Feeder	C2,D2,E2,F2,G2,K2,L2,M2,N2,P2,Q2	Complete scheme replacements
	Station Services	ST1,ST2	Complete scheme replacements
	Transmission Line	D1,H1,J1	Complete scheme replacements
	Transformer	T6,T7	Complete scheme replacements
Comalco	System Protection	SPS	Complete scheme replacement
Creek Road	Busbar	33 kV	Complete scheme replacement
	Bus Coupler	B8,C8	Complete scheme replacements
	Feeder	A2,B2,C2,D2,E2,F2,G2,H2,J2,K2,Z2	Complete scheme replacements
	Transformer	T2,T3,T4	Complete scheme replacements
Chapel Street	Capacitor Bank	A6,B6	Complete scheme replacements
	Transmission Line	B1,C1	Complete scheme replacements
Derby	Feeder	A2,B2,C2	Complete scheme replacements
	Station Services	ST1	Complete scheme replacement
	Transformer	T1A	Complete scheme replacement
Devonport	Busbar	110 kV	Complete scheme replacement
	Bus Coupler	A8,B8,A7,B7	Complete scheme replacements
	Capacitor Bank	A6,B6,C6	Complete scheme replacements
	Feeder	C2,D2,E2,F2,G2,H2,J2,K2,L2,M2,N2,P2,Q2	Complete scheme replacements
	Transmission Line	A1,B1	Complete scheme replacements
	Transformer	T1,T2,T3	Complete scheme replacements
Gordon	Transmission Line	A1,B1	Complete scheme replacements
George Town	Busbar	220 kV A scheme	Complete scheme replacement
	Capacitor Bank	A6,B6	Complete scheme replacements
	Transmission Line	Z1	Complete scheme replacement
Huon River	Busbar	11 kV	Complete scheme replacement
Kermandie	Busbar	11 kV	Complete scheme replacement
	Bus Coupler	A8	Complete scheme replacement
	Feeder	B2,C2,F2,G2,H2	Complete scheme replacements
	Station Services	ST1,ST2	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Mornington	Bus Coupler	A8	Complete scheme replacement

Location	Scheme Type	Primary Asset	Comments/Strategy
	Feeder	A2,B2,C2,D2,E2,F2,G2,H2	Complete scheme replacements
~~Norwood~~	~~Busbar~~	~~22 kV~~	~~Complete scheme replacement~~
	~~Feeder~~	~~A2,B2,C2,D2,E2,F2,G2,H2~~	~~Complete scheme replacements~~
	~~Transformer~~	~~T1,T2~~	~~Complete scheme replacements~~
Palmerston	Busbar	22 kV	Complete scheme replacement
	Bus Coupler	A7,A8	Complete scheme replacements
	Feeder	B2,C2,F2,G2,H2	Complete scheme replacements
	Station Services	ST1,ST2	Complete scheme replacements
	System Protection	NCSPS	Complete scheme replacement
	Transmission Line	A1	Complete scheme replacement
	Transformer	T1,T3,T4	Complete scheme replacements
Port Latta	Bus Coupler	A7,A8	Complete scheme replacements
	Feeder	B2,C2,E2,F2,H2,J2	Complete scheme replacements
	Station Services	ST1,ST2	Complete scheme replacements
	Transmission Line	A1,B1	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Que	Transformer	T1	Complete scheme replacement
Queenstown	Busbar	11 kV,22 kV	Complete scheme replacements
	Bus Coupler	A8,B8	Complete scheme replacements
	Feeder	A2,B2,C2,F2,G2	Complete scheme replacements
	Transformer	T1,T2,T3,T4	Complete scheme replacements
Savage River	Bus Coupler	B8	Complete scheme replacement
	Feeder	F2,G2,K2,L2,M2	Complete scheme replacements
	Station Services	ST1,ST2	Complete scheme replacements
	Transformer	T2,T3	Complete scheme replacements
Sheffield	Transmission Line	B1,C1,D1,E1,Q1	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Smithton	Busbar	22 kV	Complete scheme replacement
	Bus Coupler	A7,A8	Complete scheme replacements
	Feeder	B2,C2,D2,G2,H2,J2	Complete scheme replacements
	Transmission Line	A1,B1,D1	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Sorell	Feeder	A2,B2,C2,D2,E2,F2,G2,H2	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Temco	System Protection	SPS	Complete scheme replacement
	Transmission Line	A1,B1	Complete scheme replacements

Location	Scheme Type	Primary Asset	Comments/Strategy
Ulverstone	Feeder	A2,B2,C2,D2,E2,F2	Complete scheme replacements
	Transformer	T1,T2	Complete scheme replacements
Waddamana	Transmission Line	DE1,FG1,GH1,HD1	Complete scheme replacements
	Transformer	T1	Complete scheme replacement
Wesley Vale	Bus Coupler	A7,C8	Complete scheme replacements
	Feeder	K2,L2,M2,N2,P2,Q2	Complete scheme replacements
	Transmission Line	A1,B1	Complete scheme replacements
	Transformer	T3,T4	Complete scheme replacements
Nyrstar	System Protection	SPS	Complete scheme replacement