Protection Relay replacement (NPR)

Regulatory Business Case (RBC) 2024-29

PowerWater

Contents

1. Summary

This business case has been prepared to support the 2024-29 Regulatory Proposal. The business case demonstrates that Power and Water has undertaken appropriate analysis of the need for the expenditure and identified credible options that will resolve the need and ensure that Power and Water continues to meet the National Electricity Objectives and maintain the quality, reliability, and security of supply of standard control services and maintain the safety of the distribution system.

The proposed expenditure identified in this business case will undergo further assessment and scrutiny through Power and Water's normal governance processes prior to implementation and delivery.

This business case addresses the condition, compliance and obsolescence risks of protection relays.

1.1 Business need

Protection relays form a critical part of modern power systems, providing safety and reliability to customers and protecting assets against damage from operations outside the design operating range. Protection relays are typically associated with tripping the circuit breakers when an abnormality is detected in the network parameters like voltages, currents and frequency.

If the primary protection device fails to operate, the local or remote backup protection will operate to clear the fault, however, the operation time will be longer. The longer operation time increases the risk to public, particularly if a fault is related to public contact with equipment and may impact the power system stability if it is a transmission system fault. The number of customers affected by the operation will be larger as backup protection will generally result in the loss of supply to a large proportion, if not all, customers supplied from a zone substation.

There are currently 1,364 relays on the network with the older, non-self-monitored, electromechanical relays largely replaced over the past decade (the electromechanical assets were installed prior to the change in technology to faster acting /static relay technologies from the 1980's). The majority of the relay population is based on digital relay technology, with approximately one third of the population still comprised of the static electronic relays targeted by this program.

Approximately 30% of the protection relay population are over 20 Years old, and by the end of the regulatory period this will increase further. The vast majority of those are static relays, and which are operating well beyond their expected design lives. Similarly, there are first generation digital relays, which are not supported by the manufacturers and will be approaching or past the economic life at the end of the regulatory period. There are also a smaller population of electromechanical relays remaining in operation and these should be replaced.

In addition, the static and first generation digital relays present:

- Compliance issues with more stringent incident reporting obligations.
- Compliance issues with the Technical Code around redundant (X-Y) protection schemes needed for equipment operating at 66kV and above - relevant to static protection relays at Hudson Creek and Channel Island.
- Expiry of vendor support / technical obsolescence.

- Elevated failure risks – particularly in relation to safety and reliability

Alongside the above risks, Power and Water has insufficient systems to enable investigation and recording of events to meet the requirements of System Control, or to effectively manage protection settings to facilitate Technical Code co-ordination obligations. These capabilities are critical to leverage the network flexibility benefits of remote management of the digital relay fleet.

1.2 Options analysis

There are limited viable options to resolve this need outside the replacement of the relays at some point in the future. Hence, the option analysis focusses on the cost, risk and prudence of options considered in Table 1.

The options considered to resolve this need are shown in Table 2.

Table 1 Summary of credible options

Option No.	Option name	Description	Recommended
1	Repair on failure with recovered spares	Repair units on failure with emergency spares recovered from other sites – to allow operation until planned replacement	No
2	Targeted Planned Replacement	Target replacement of units based on compliance requirements, type vulnerabilities, lack of manufacturer support and/or spares availability	Yes
3	Replace on failure	Replace units on failure	No

As part of a holistic assessment, non-network solutions, capex/opex trade-offs and retirement or derating options were also considered, but found that none of these options addressed the underlying network issues.

A cost benefit analysis was completed for each of the options where the risk reduction, compared to Option 1, was used as the benefit achieved by the option.

1.3 Recommendation

Option 2 is recommended to efficiently manage the removal of the static relay fleet from the network over time, whilst maximising the safe and reliable service life of obsolete models and types of relays at an estimated cost of $10.3 million (real 2021/22).

This option includes:

- Starts to address the risk associated with the static relays operating beyond economic life by adopting a targeted replacement with digital relays.

- Starts to address the risk associated with the first generation digital relays, made obsolete by manufacturers, by adopting a targeted replacement. The relays from site will be provisioned as spares for future.
- Ensure compliance with Power and Water's increased obligations and stricter timeframes for investigations and reporting to System Control, by addition of 8 digital fault recorders.
- Address a known non-compliance with the redundant protection requirements of the Technical Code, by replacement of 8 non fully compliant protection schemes.
- Implement a modern integrated protection settings management software to transition into the life time management of protection settings which will help ensure correct settings are applied to the relay in a secure and efficient way throughout its life cycle.

Table 3 shows a summary of the expenditure requirements for the 2024-29 regulatory period.

Table 2 Annual capital and operational expenditure ($'000, real 2021/22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	2,784	1,323	2,352	2,064	1,754	10,277
Opex	-	-	-	-	-	-
Total	**2,784**	**1,323**	**2,352**	**2,064**	**1,754**	**10,277**

The replace on failure options (Option 1 and Option 3) does not address key obsolescence and compliance risks present in the current protection relay population. Security vulnerabilities are also not addressed by solutions that maintain a greater number of technically obsolete and unsupported relays in service for an extended period. Deferring this program, introduced additional security and reliability risks for the power system, and future deliverability of replacement programs.

The recommended option enables the timely availability of system fault data for incident investigations and facilitates improved control, monitoring and flexibility in the network that will be required to accommodate higher volumes of DER that is expected under NT Govt emissions targets and the Power and Water future network strategy.

2 Identified need

This section provides the background and context to this business case, identifies the issues that are posing increasing risks of obsolescence and non-compliant protection relays to Power and Water and its customers, describes the current mitigation program and its delivery status, highlights the consequence of asset failure, and provides a risk assessment of the inherent risk if no investment is undertaken.

2.1 Asset profile

2.1.1 Asset population

Table 4 shows the population characteristics of protection relays. Approximately one third of the population are older-style static and electromechanical relays that have reached or exceeded their expected serviceable life.

Table 3 Protection relay population

Relay Type/Operating Voltage	Number
Digital	**890** (65%)
11 kV	345
132 kV	60
22 kV	138
66 kV	347
Static	**463** (34%)
11 kV	179
132 kV	92
22 kV	46
66 kV	146
Remaining Electromechanical (7 @ 11kV, 4 @ 66kV)	**11** (1%)
Network Total	**1,364 (100%)**

2.1.2 Asset lives

The expected asset lives for protection relays is shown in the table below. [1]

Table 4 Protection relay lives

Relay Type	Asset life assumption
Digital	20 years
Static	20 years
Electromechanical	30 years

Experience tells us that the typical life of static relays is shorter, at around 15-20 years. This means that the replacement of the earlier static units have coincided with the approximate end of life of much of the electromechanical relay population in recent years. Therefore, with the vast majority of risk arising from the electromechanical relays addressed through recent replacement works, the focus for the 2024-29 regulatory period is on the replacement of the earlier 'static' relays.

2.1.3 Age profile

Figure 2 shows the age profile of protection relay assets split by technology class.

Approximately 30% of the protection relay population are over 20 Years old, and by the end of the regulatory period this will increase further. The vast majority of those are static and first generation digital relays, which are operating well beyond their expected design lives. There are also a smaller population of electromechanical relays remaining in operation and these should be replaced.

[1] PWC Asset Management Plan 2018 states expected lives of relays as 20 years for digital and static and 30 years for electromechanical. Gurevich, 2009 in 'Reliability of microprocessor-based protective devices – revisited', acknowledges a normal life expectation of 20-25 years for microprocessor-based protective devices but refers to an actual life expectancy of approximately 5 years.

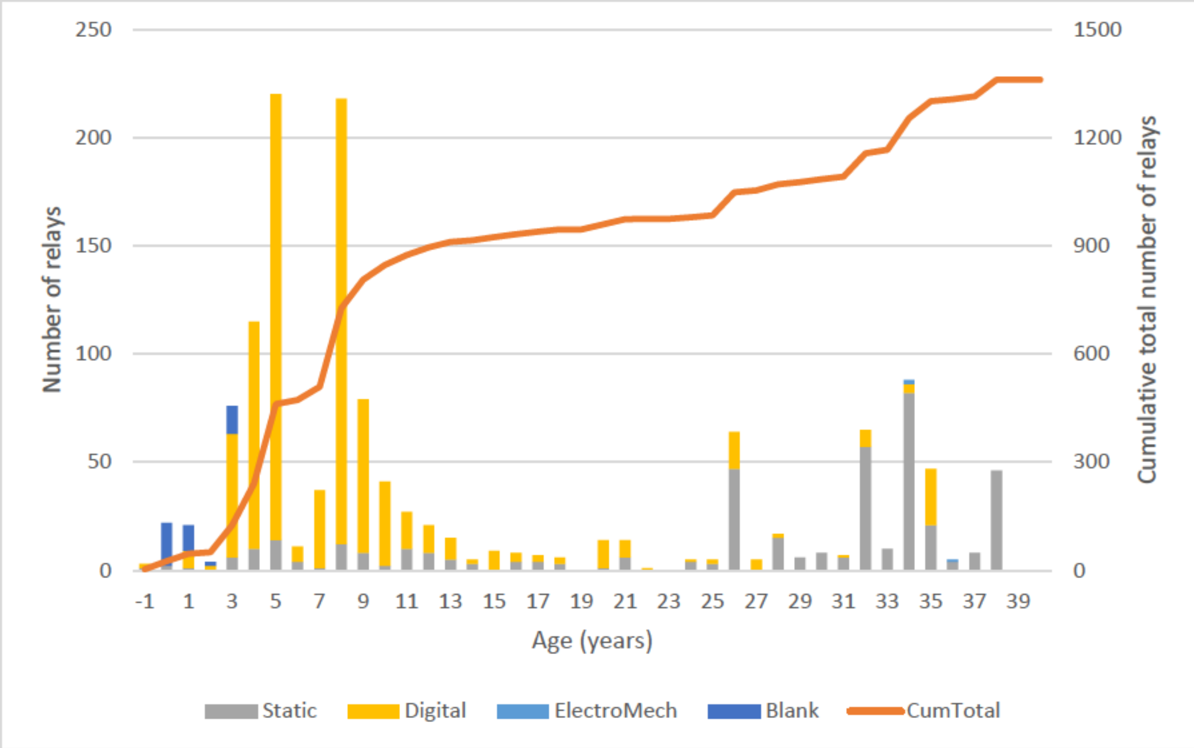

Figure 1 Protection relays - age and technology class

2.2 Compliance obligations

Power and Water is obliged to:

- Maintain fully independent duplicate protection schemes for equipment connected at voltages above 66kV under section 2.9.2 of the Network Technical Code.
- Meet reporting and investigation timeframes as set out in the System Control Technical Code (Section 7 – Power System Incident Reporting Procedures).

2.2.1 Network Technical Code and Network Planning Criteria

The Network Technical Code and Network Planning Criteria requires that equipment connected at voltages of 66kV and above[2]:

- Primary equipment shall be protected by a main protection system that shall remove from service only those items of primary equipment directly affected by a fault.
- The main protection system shall comprise two fully independent protection schemes of differing principle, connected to operate in a "one out of two" arrangement

[2] The full duplication of protection requirements for equipment connected at voltages of 66kV and above can be found in Section 2.9.2.1 of the PWC Network Technical code and Network Planning Criteria 2020

Protection System Settings Management Software is required to fulfil the necessity to effectively manage the settings applied to Protection and Control device throughout its lifecycle. Similarly, integration between the setting management suite and the power system modelling software will facilitate rigorous studies mandated in the Network Technical Code obligations for Power System simulation studies, User Facilities Islanding co-ordination, Impact on Power System Security, Protection Settings Co-ordination among other protection setting co-ordination and management responsibilities[3].

2.2.2 System Control Technical Code

Alongside protection relays, the installation of associated digital fault recorders is also required to facilitate compliance with the stringent investigation and reporting timeframes that have been introduced by System Control from October 2021.

These guidelines place more stringent incident reporting timeframes (of 5-20 business days) on certain power system incidents that requires the evaluation of relevant data, asset configuration and operating environment – including how protection relays operated (or failed to operate) and how other relevant factors lead to the incident. Modern digital fault recorders allow monitoring and data access via the corporate ICT network without posing a cybersecurity risk to the electricity network. The reporting requirements for System Control are outlined in Appendix A.

The communication and control functionality of modern relays deliver substantial operational and reliability benefits. In particular, the transient data reporting capability to support investigations, improve operational flexibility and analytical data capture benefits are required to support the more stringent reporting obligations under the new guideline in a manner that maintains secure data systems separation.

However, the technology also introduces risks of cybersecurity vulnerabilities and generally provide no indicators of deterioration prior to failure, therefore ongoing vendor support is required for modern relays. Removing the ongoing reliance on aged and technically obsolete electronic relays for critical safety and reliability functions in the PWC network mitigates these cybersecurity and sudden failure risks due to retaining older relay types in service.

2.3 Historical and current management programs

The protection relay fleet is tested periodically to verify the functionality. The frequency of testing depends on relay type and classification. The relay will be replaced by an identical relay or an equivalent if found to be defective. In addition, when type/batch issues are identified for a batch or relay model, targeted replacement programs will be established as required.

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[3] For example, NTC 3.2.1 (Simulation Study inputs), NTC 3.2.3.8 and NTC 2.2 (Islanding of a User's Facilities compatibility with Network), NTC 3.3.5.9 (Protection Systems that Impact on Power System Security), NTC 6 esp. 6.1.3 to 6.1.6 (Protection Settings Co-ordination), 7 (Commissioning), 11)

Power and Water has undertaken a targeted replacement program of older electromechanical protection relays in the current regulatory period. In addition, the major replacement projects typically include replacement of secondary systems including protection relays. Electromechanical relays were primarily installed in the 1980's and are generally well beyond the end of their expected serviceable lives.

The major projects already committed that will result in replacement of some of the oldest relays on the networks are listed in Table 6.

Table 5 Replacements planned for the current regulatory period

Location and protection type	Action	Schedule
Palmerston Transformer differential and bus tie protection	Replacement	2023
Hudson Creek transformer and bus tie protection	Replacement	2023
DKTL secondary systems: 132kV protection at Manton, Batchelor, Katherine and Pine Creek)	Replacement	2023-24
Berrimah zone substation	Replacement	2023-25
Tindal zone substation	Replacement	2023-25
Humpty Doo zone substation	Decommission	2024
Centre Yard zone substation	Decommission	2024
Sadadeen 22kV switchboard	Decommission	2024-25

In many cases, where electromechanical or static relays will be replaced the replacement is 'many to one'. Modern digital relays provide multiple protection functions whereas static and electromechanical relays only provide a single function. Therefore, one modern digital relay can replace multiple static and electromechanically relays and still provide the same, or an improved, protection scheme.

The replacement program, including major projects, will result in the removal of a significant number of aged relays. Between 2024-25 and 2028-29 there will be 89 relays expected to exceed their technical lives. This allows for a targeted program to address the highest risk protection relays while minimising costs.

Figure 1 shows the historical capex incurred on the protection relay replacement program, which averages approximately $0.7 million (real 2021/22) p.a. over the 2019-24 regulatory period.

To provide an indication of the scope of protection relay replacement underway in the current period, the protection relay works associated with the Berrimah substation replacement and Darwin-Katherine transmission line secondary system upgrade[4] were added to the figure below. With the addition of these projects, the average annual expenditure for protection relay replacement increases to approximately $1.5 million (real 2021/22) p.a. over the 2019-24 regulatory period. With these additions, the replacement rate and level of expenditure more reasonably reflects a sustainable replacement level.

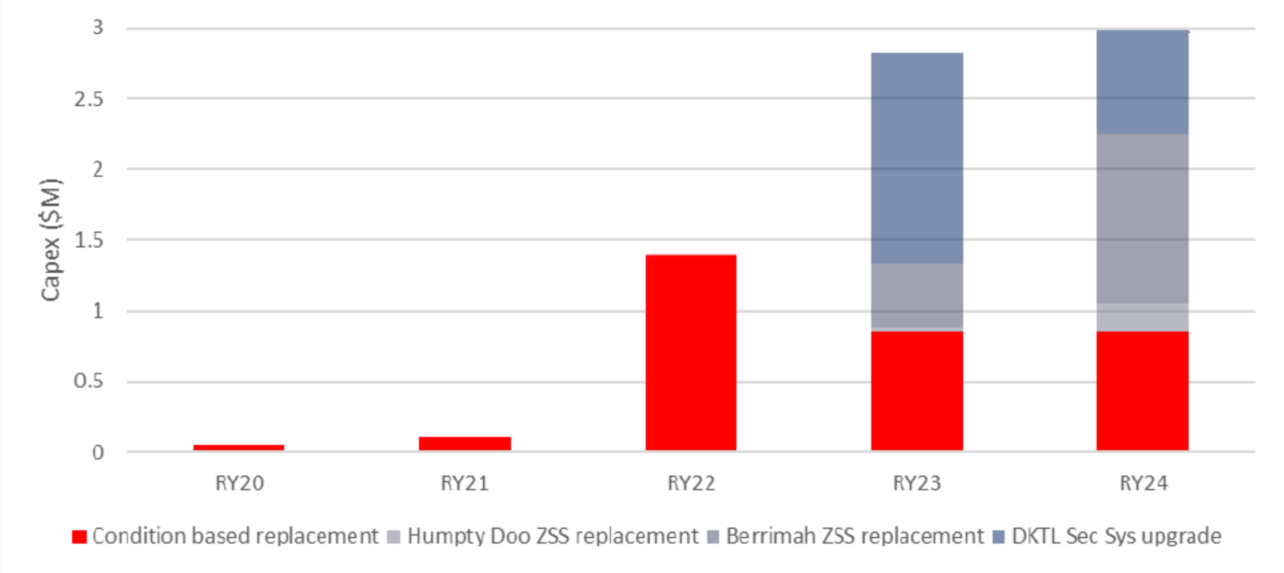

Figure 2: Historical and forecast expenditure on a yearly basis and averaged across the RY20-24 regulatory period

2.4 Emerging issues and risks

2.4.1 Overview

The management of relay populations on electricity networks needs to consider a broad range of factors including:

- Compliance obligations
- Type vulnerabilities
- Manufacturer support (e.g. firmware upgrades and security bulletins)
- Underlying technology (electromechanical, electronic, microprocessor controlled)
- Equipment performance (such as operating times)
- Data monitoring and control flexibility
- Obsolescence

The cost of relays is modest in relation to the scale of outage that can be caused by over-sensitive or malfunctioning relays and/or poorly configured schemes. Under unfavourable conditions, this can lead to protection systems acting in a way that reinforces system instability, leading to cascading protection operations and wide spread outages. Examples of protection relay issues causing significant outages

[4] There are other projects with historical protection relay costs that could also be added and in doing so would result in a higher annal average expenditure

include protection setting issues at wind farms contributing to the 2016 South Australian system black, the 2021 widespread blackout in Qld and Northern NSW following the Callide incident and potentially over sensitive reverse power protection settings were identified as a contributor to black start performance in the review of the 2019 Alice Springs System Black event in the NT.

As a result, modern relays provide essential control, safety and flexibility services in the network, complemented by the ability to record high resolution event data and provide remote monitoring, configuration and control to better respond to the increasing levels of variable renewable electricity on the grid.

Several types of protection relay are no longer supported by the manufacturer and represent increasingly obsolete technology, resulting in actual or expected compliance issues over the next regulatory control period.

2.4.2 Technology obsolescence

Over the past 20-30 years, Electromechanical relays have become technologically obsolete with increasing difficulty to maintain due to the lack of necessary precision mechanical components, inability to economically obtain spares, limited monitoring and control capabilities as well as a reducing industry skill base for these technologies.

The older, slower acting, non-self-monitored electromechanical relays have largely been replaced over the past decade. The majority of the relay population is now based on digital relay technology, with approximately one third of the population still comprised of the static electronic relays targeted by this program.

The static relays providing a single protection function and first generation digital relays are now reaching the point where they need to be retired due to:

- Compliance issues with more stringent incident reporting obligations
- Compliance issues with the Technical Code around redundant (X-Y) protection schemes needed for equipment operating at 66kV and above - relevant to static protection relays at Hudson Creek and Channel Island
- Expiry of vendor support
- Failure risks – particularly in relation to safety and reliability

These earlier static relays contain more discrete electronic components that are prone to failure with time and operating environment factors such as corrosion/cracking of solder joints high operating temperatures and high humidity.

The expected life of static relays has reduced over this time reflecting the broader trend to shorter life, lower maintenance, microprocessor based control systems that are now more versatile, require minimal maintenance and better support the more advanced functionality that is required to deliver the flexibility in grid operations that is essential to accommodating higher volumes of renewables in the system. This means that adjustments to protection settings can now be made in software rather than the mechanical springs, screws and gears of electromechanical systems, and the relay logic controllers can often process information to provide several protection functions within a single unit.

2.4.3 Annual failures

Each year, Power and Water experiences random failure of protection relays. These failures are not necessarily age related and have covered a variety of relay makes and models. The rectification of the relays that have been capitalised against the NPR program has ranged from replacement relays using the same relay type to minimise costs through to replacement of individual cards or other parts. In 2020-21 and 2021-22 failures cost $106,030 and $97,260, (real 2021-22) respectively.

2.4.4 Current non-compliance

Power and Water has identified the need to install independent, duplicate protection schemes on equipment operating at 66kV and above at Hudson Creek and Channel Island, which are both important locations in the network. This results in the planned replacement of 8 static protection relays (see section 4.6 for details).

Channel Island is the location of Territory Generation's largest base load power station and the new utility scale battery. It has previously experienced incidents which have affected the entire Darwin-Katherine system. As a result, relays with fault recording capability at these locations is needed to support investigations, compliance and incident response.

It has been acknowledged and managed for several years, given the age of the assets. However, the relays are showing some physical signs of deterioration now that they are reaching a relatively advanced age, lack data recording capability and show signs of physical degradation. In addition, the increasing need for network flexibility and resilience over the period to 2029 means that it has become prudent to rectify the non-compliance with the Technical Code in relation to X-Y protection schemes at Channel Island and Hudson Creek.

This will further support the NT Government and Commonwealth renewable energy and carbon reduction targets for 2030 – which are expected to drive much higher levels of solar, storage and distributed energy onto the grid and create larger daily and seasonal volatility in energy flows across the system.

The program will also enable data recording at the sites which, as transmission substations, would typically be associated with major incident investigations where more detailed analysis of the relay data would usually be required relatively quickly to support the required reporting timeframes.

2.4.5 Growing Protection Co-ordination Challenges

In recent years the volume of new renewable generation connections and customer owned storage, generation, load management schemes and microgrids have meant that system studies for connections and alterations have increased in volume and complexity across the country.

This requires more detailed management of protection settings information and ideally deployment, verification and ongoing audit of setting changes to field devices via secure and remote configuration systems, rather than physical attendance on site. Enabling remote access to protection devices will also mitigate risks during the wet season when some sites may be inaccessible.

The proven integration of Protection Setting Setting Management suite with the DigSilent PowerFactory tools used by Power and Water, as well as more variable daily and seasonal power flow and much greater volume of possible generator/load operating configurations mean that the automation, management and integration with planning tools is critical for the mitigation of cascading or widespread 'common cause' protection failures[5].

To mitigate implementation risks and skills gaps, Power and Water is adopting a proven protection systems management solution from the same vendor as the industry standard PowerFactory simulation tool. This combination is already successfully deployed within Western Power, Horizon Power and most of the NEM businesses.

2.4.6 Technology transition

Modern relays are based on microprocessor (digital) control and provide multiple protection functions within each device, diagnostic capabilities that support the required investigations into abnormal operations, and timely reporting to System Control. Modern relays are also able to communicate via the SCADA system and the restricted-access engineering ICT network to provide operational information to System Control.

Additional data logging from modern relays and substation data recorders enables:

- **data historian functionality** to support analysis of substation operations during unusual events and to evaluate changes in loading, protection settings and system stability over time. Appropriate data logging to the broader corporate network allows the relay operating history to be accessed via the corporate ICT network, whilst restricting the critical control functionality to the restricted access ICT network.
- **remote communication and/or control capabilities** to enable the remote monitoring of status and the adjustment of protection settings without physical attendance at the substation.

This functionality, now required for compliance with reporting requirements and for managing the increasingly complex network, is not available on electromechanical and older static relays.

2.4.7 An industry wide issue

The technology transition for relays is a common theme among Australian and international distribution and transmission businesses. The core issues include:

- Errors, inconsistencies or missing data
- Availability of spares and lack of firmware upgrade support from suppliers
- Manufacture defects and increasing failure rates
- Non-compliance with existing standards

[5] Recent examples of high profile protection failures and near misses include the Callide Qld and Northern NSW Outage cascading following generator disconnections, SA Rooftop Solar common disconnection thresholds causing imbalance and risk of SA-VIC interconnector trips leading to AEMO/Network centralised control of rooftop inverter disconnection, SA System Black 'common cause' fault ride through settings on wind farms

- Incompatibility with modern communication systems[6]

The need for protection settings to be managed more dynamically and deployed more rapidly is increasing as generation/load and storage transition to renewables to ensure the security the system against common cause protection failures that had not previously been considered a credible threat.

The predominate asset strategy for digital relay assets is to monitor OEM firmware upgrades and type issues to assess the risk exposure against the security, type vulnerabilities and failure history. These risks will be mitigated by existing spare holdings and the ability to stage replacements over time so that retired units can be retained to serve as emergency replacements for the remaining population.

In many cases, the end of OEM support for particular relay types serves as a marker for the planned retirement of the population. This is because replacement relays are typically a different physical size and shape – requiring extensive modifications to switchboard panels, often making it preferable to replace a protection scheme panels as an assembly rather than address individual relays. The longer the relay is out of support, the more likely there are unknown and unaddressed type issues and security vulnerabilities that have emerged since the final firmware upgrades and OEM service notifications for the model type.

Importantly, the limited redundancy in protection schemes at distribution level means that relay failures have a greater likelihood of supply loss. Since the quantum of energy is significantly lower than for transmission networks, the beneficial technology diversification strategies adopted for transmission networks are not economic for most distribution networks[7].

2.5 Risk assessment

Power and Water has developed the Risk Quantification Procedure to enable consistent quantification of risk from their assets into dollar terms. The procedure is applicable to most assets where there is a direct link between an asset failure and the impact of that failure on the defined consequence categories.

Power and Water does not have adequate data to undertake a quantitative analysis for protection relays, so a qualitative assessment of the risk, based on the key consequence areas set out in the Risk Quantification Procedure, is provided below.

2.5.1 Health and Safety

Asset faults, in particular faults on the distribution network can present a safety risk to the public, in particular, when power lines fall to the ground. This can occur through direct contact with the faulted asset, potential rises in close proximity to the fault, or via other conductive materials such as metal fences. Protection is critical to detect these faults, including fault currents, over voltages and sensitive earth faults, and act to interrupt supply by opening the circuit breaker. By completing this function, protection relays remove faults as quickly as practicable and maintain the safety performance of the network.

[6] These issues have also been identified by ElectraNet's in its recent RIT-T PSCR and PACR, available here and the Energex Asset Management Plan for Protection, see Attachment 7.038 to the Energex 2020-2025 Regulatory Proposal, available here

[7] where older relays are used in parallel with newer technologies for the redundant protection scheme

Failure of a relay will result in a fault being sustained for a longer period of time until the backup device operates. This will result in more energy transferred into the fault and increase the risk to the public and field crews.

As the network changes rapidly with the transition to renewable power, protection settings will require review and potentially updating to make sure the grading across all network devices remains appropriate as fault levels and power flows change.

2.5.2 Compliance

Power and Water has compliance obligations established by the network licence and the Power Networks Network Technical Code and Network Planning Criteria. Specifically, Section 2.9 Protection Arrangements which details requirements for safe and reliable management of protection systems to maintain a safe, reliable and secure system. Failure to comply can result in financial penalties.

Manufacturers provide support for protection relays that includes addressing security vulnerabilities. These are usually managed by notifications, bulletins and firmware upgrades from the manufacturer during the support period. Updates for equipment are typically relatively frequent given the life of the asset, with several updates issued. Once the assets are no longer supported, the risk of unidentified type issues and security vulnerabilities increases with time. This will impact Power and Water's ability to comply with requirements of the Security of Critical Infrastructure (SOCI) Act 2018.[8]

2.5.3 Reliability (if not compliance obligation)

If a protection device fails to operate, the remote or local backup device will operate to clear the fault, however, the operation time will be longer and the number of customers affected by the operation will be larger. This will result in a larger impact on reliability performance metrics (SAIDI and SAIFI), and can result in non-compliance with the targets that are set by the Utilities Commission of the Northern Territory. Allowing all relays to remain in service until they functionally fail is not an acceptable practice and would result in poorer reliability outcomes for customers.

If a protection relay does fail, then replacement will become increasingly difficult due to incompatibility of the existing protection panel with modern assets. This increases the cost and implementation time of each reactive replacement, negatively affecting customers.

2.5.4 Assessment

The qualitative risk assessment of the inherent risk and targeted risk is shown in Figure 3 using the matrix approach set out in the Enterprise Risk Management Standard.

[8] In March and April 2022 the Security of Critical Infrastructure (SOCI) Act 2018 was amended to strengthen the security and resilience of critical infrastructure by expanding the sectors and asset classes the SOCI Act applies to, and to introduce new obligations.

	Insignficiant	Minor	Moderate	Major	Severe
Almost certain	Medium	High	Very High	Extreme	Extreme
Likely	Low	Medium	High	Very High	Extreme
Possible	Low	Low	Medium	High	Very High
Unlikely	Low	Low	Medium	High	High
Rare	Low	Low	Low	Medium	Medium

Figure 3 Qualitative risk assessment

2.6 Summary

Power and Water has a fleet of 1,364 protection relays of which 34% are static or electromechanical. The majority of these are over their design life of 20 Years old, and by the end of the regulatory period this will increase further. These relays are no longer supported by the manufacturer and represent an increasing risk to the safe and reliable operation of the network.

Further, the technical obsolescence of these assets results in:

- Protection coordination and operation challenges.
- Limitations with data recording which is essential for investigations into faults.
- Limitations with communicating remotely with devices, generally requiring staff to be on site to make setting changes or download data.
- Errors, inconsistencies or missing data
- Limited availability of spares.
- Lack of firmware upgrade support from suppliers which can result in cyber security vulnerabilities.

The limitations listed above mean that Power and Water is currently not compliant with two requirements of the Network Technical Code and System Control Technical Code. Under the codes, Power and Water must:

- Maintain fully independent duplicate protection schemes for equipment connected at voltages above 66kV under section 2.9.2 of the Network Technical Code.
- Meet reporting and investigation timeframes as set out in the System Control Technical Code (Section 7 – Power System Incident Reporting Procedures).

Section 3 below describes the options considered to address the risks and deficiencies identified in the protection relay fleet.

3 Options analysis

This section describes the various options that were analysed to address the increasing risk and identify the recommended option. The options are analysed based on ability to address the identified needs, prudency and efficiency, commercial and technical feasibility, deliverability, benefits and an optimal balance between long term asset risk and short-term asset performance.

3.1 Comparison of credible options

Credible options are identified as options that address the identified need, are technically feasible and can be implemented within the required timeframe. The following options have been identified:

- Option 1 – Repair on failure with recovered spares. This option proposes to allow relays to run to failure to maximise the service life of the existing population of relays, and repair with recovered spares.
- Option 2 – Targeted Planned Replacement. This option involves the targeted selection of relays and/or sites for replacement activities to allow the management of obsolete and non-compliant relays.
- Option 3 – Replace on Failure w/modern equivalent. This option involves the replacement of relays upon failure with modern equivalent units (rather than emergency replacement from recovered spares).

A comparison of the three identified credible options and the issues they address in the identified need is depicted in Table 5 below.

These options are described and assessed in detail in the sections below.

Table 6 Summary of options analysis outcomes

Assessment metrics	Option 1	Option 2	Option 3
NPC[9] ($'000, real FY22)	>Option 2	9,964[10]	>Option 2
Capex ($'000, real FY22)	<Option 2	10,267	Note 1.
Meets customer expectations	◑	◕	◑
Aligns with Asset Objectives	○	◕	○
Technical Viability	◑	◕	○

[9] Net Present Cost (NPC) equates the total cost of a project over a specified time period to the total cost today, taking into account the time value of money.
[10] An NPC of $9.789M is based on a WACC of 2.75 per cent. Sensitivities with a WACC of 2.25 per cent and 3.25 per cent result in NPCs of $9.884M and $9.725M, respectively.

Deliverability	◑	●	○
Preferred	×	✓	×

● Fully addressed the issue ◕ Adequately addressed the issue ◑ Partially addressed the issue ○ Did not address the issue

Note 1. The capex depends on costs of stocking and replacing with modern equivalent spares

3.1.1 Option 1 – Repair on failure with recovered spares

Option 1 proposes to allow relays to run to failure to maximise the service life of the existing population of relays, and repair with spares previously recovered from replaced relays. This minimises the volume of planned replacements but results in an increasing exposure to type issues, higher failure rates and security vulnerabilities from obsolete relay types.

Importantly the adoption of this option relies on the provision of sufficient spares for the affected relay types to ensure that the reclaimed spares remain available and serviceable for emergency replacement. This cannot be assured, as spares are no longer available from manufacturers and only limited spare units and components are available within Power and Water. Otherwise, the unplanned replacement of a failed relay, without a like-for like (same model) replacement unit, can involve significant modification of panels, or otherwise lead to extended outages whilst alternative solutions are evaluated. A full evaluation of the spares holdings at Power and Water would be required. It is considered unlikely to be technically feasible for the five-year period.

In addition, the older electronic relays also do not meet the requirements of the current operating and reporting standards including data recording, communications and control functionality of modern relays. Allowing relays to run to failure would delay the implementation of more flexible solutions at the same time as the challenges of more dynamic network operating environment (during the transition to renewables) can benefit the from reporting, control and reliability improvements that modern relays enable.

This option does not adequately mitigate the growing compliance issues over the next regulatory control period or adequately mitigate the increasing risk posed by non-compliant (no duplication) protection schemes at transmission level. Accordingly this option has not been financially assessed. This option is not recommended.

3.1.2 Option 2 – Targeted Planned Replacement

Option 2 proposes the targeted replacement of relays and/or sites to mitigate the obsolescence risk and current non-compliance at the transmission level at an estimated cost of $10.3 million (real 2021/22).

The central part of this program includes replacement of 92 protection relays that are obsolete, out of manufacturer support or have condition issues, addition of 8 relays to implement the fully independent x-y protection schemes to achieve compliance on the 66kV lines, the addition of 8 new digital fault recorders across the Power and Water network, and retirement of 11 relays related to the retirement of the

Sadadeen 22kV switchboard. This option will address the inherent risk and enable Power and Water to achieve the Target Risk as shown in Figure 3.

The 92 obsolete relays will be replaced by 75 relays due to the improved functionality of modern relays enabling a many to one replacement. The planned program allows for the planning and design of the necessary modifications of decades old panels to accommodate modern relays can be extensive and significantly add to costs and the time to implement.

The scale of the program was determined based on the age and type of relays that will reach the end of their technical life by the end of the 2024-29 regulatory period. Any relays planned to be addressed during the current period or by other projects in the next period have been excluded. The program has been scheduled by grouping the relays by zone substation to improve the efficiency of the replacements.

In addition, an allowance has been included for replacement of relays that fail in service, based on historical expenditure as described in section 2.4. Due to the replacement and retirement of assets, we have assumed a reduced level of failures at 50% of the historical rate. Units that are still serviceable would be salvaged and retained as part of the Power and Water emergency spares to manage the end of life once relays that are no longer supported by the manufacturer. This allows Power and Water to extend the service life of the remaining population of obsolete in-service relays as far as practicable as it reduces the volume of obsolete assets (and therefore risk associated with these relays) on the network over time.

This option replaces vulnerable relay types with modern, faster acting and more configurable relays to enable Power and Water to comply with new incident reporting timeframes and address Network Technical Code non-compliances for duplicate protection on the transmission network.

In response to the requirements of System Control, Power and Water also propose to install 8 substation data recorders as part of the relay replacement program for 2024-29 regulatory period. The digital fault recorder provide engineering and corporate access to the power system data that is required to complete incident investigations within the timeframes required by the System Control guidelines.

The remote nature of Power and Water's network means that travel times for physical attendance to deploy protection settings changes are costly, and operational concerns with protection systems also need to be verified on site. The volume of protection settings changes that is required is expected to increase, as is the need to manage the settings databases more robustly alongside power systems modelling tools that rely on accurate protection settings information for generation or load proponents connecting to, or altering, their installations performance standards or network access agreements.

This option includes implementation of integrated protection settings management software to mitigate a range of credible system transition risks such as duplicated system studies due to outdated (or otherwise unverified/audited) protection settings or over constraint of renewables, DER and storage. The Protection Settings Management Software (t is required to smoothly manage the growing population of digital relays, implementing the philosophy of life-time management of protection settings. Also, the integration of the setting management suite with the standard power system modelling software will facilitate performing rigorous power system studies and validate the performance of protection schemes under the changing generation mix.

This option is recommended.

3.1.3 Option 3 – Replace on failure

Option 3 proposes to replace relays upon failure with modern equivalent units (rather than emergency replacement from recovered spares). This would theoretically minimise the number of relays being replaced but, without a 'same model' plug in replacement, the necessary modifications of decades old panels to accommodate modern relays can be extensive and significantly add to costs and the time to implement.

Allowing relays to fail without an appropriately planned emergency spares strategy in place is not prudent and would place greater compliance, safety and reliability risk exposures on Power and Water.

Whilst this option would maximise the life of individual relay units, the additional cost of panel modifications and extended repair time for unplanned emergency replacement would typically result in higher costs from the reactive approach than the planned program. Notwithstanding this, over a short timeframe, this approach may also prove beneficial when actual in service failures remain at low levels. In practice, the broadly equal exposure to higher costs from more expensive and time critical reactive replacement work would detract from the attractiveness of this strategy.

However, the escalating compliance risk and impact on reporting timeframes and operational flexibility mean that this option would only be viable in the short term management of works to respond to a severely capital constrained or highly uncertain planning environment.

This option does not adequately mitigate the growing compliance issues over the next regulatory control period or adequately mitigate the increasing risk posed by non-compliant (no duplication) protection schemes at transmission level. Accordingly this option has not been financially assessed.

This option is not recommended.

3.2 Non-credible options

Our analysis also identified a number of options found to be non-credible. These options are described below and were not taken through to detail analysis for the reasons provided.

3.2.1 Retire or de-rate assets to extend life – does not address the need

The options for immediate retirement of obsolete relay assets are limited and would result in much higher expenditure than the targeted, planned replacement option.

3.2.2 Non-Network alternatives – does not address the need

Due to the type and function of these assets, there are no non-network alternatives or solutions that can be implemented in place of direct asset replacement with like for like (modern equivalent) assets. When relays are identified as problematic, non-compliant or obsolete PWC undertakes an assessment of whether the protection scheme can be optimised to reduce cost (e.g. via consolidation to multi-function relays) or to meet future demand more efficiently (e.g. communications, control and data recording functionality to improve network flexibility and support timely reporting).

In this case, non-network solutions cannot provide the protection capability that the existing relays do, or the monitoring and control capability that the replacement relays will enable.

3.2.3 Capex/Opex Substitution – does not address the need

Since the driver of this investment is significant deterioration across a fleet of assets caused by the same common technical drivers and market support practices of suppliers, it is not feasible to substitute capital expenditure with operational expenditure to resolve the risk. Whilst ultimately designed as a high reliability device, electronic relays typically exhibit no signs of deterioration prior to failure. Firmware upgrades and security bulletins are frequently issued throughout the whole support life of the equipment, meaning that there is limited confidence that type issues and security vulnerabilities have adequately been addressed once vendor support ends. This risk significantly increases the longer that the equipment has been out of support.

Whilst additional opex to test protection functionality can be deployed to verify that units are still working as intended, the nature of electronics is such that this only provides a 'point-in-time' verification, with no assurance that there are no intermittent issues or whether or not the unit can remain serviceable until the next inspection/test. These methods can be beneficial to improve the detection rates of already failed relays that remain in service – but have not been required to operate since failure – but are typically less effective at identifying condition issues with relays that are likely to fail in the near future.

For this reason only capital expenditure to manage risk levels whilst the relays are removed from the network will resolve the underlying issues.

3.2.4 Defer Deployment of New Protection Settings Management Software – does not address the need

Protection co-ordination issues have already caused widespread outages and material economic damages in most of the NEM states at some point in the past 5-10 years. With the volume of renewables, DER, reduced reliance on gas and growth in utility scale solar and hydrogen industries in the NT, the challenge of protection co-ordination is expected to increase substantially with the accelerating rate of change.

The implementation of integrated protection settings management software mitigates a range of credible system transition risks such as duplicated system studies due to outdated (or otherwise unverified/audited) protection settings or over constraint of renewables, DER and storage. It also allows the lifecycle management of protection settings.

3.2.5 Defer replacement of non-compliant 66kV relays – does not address the need

Continuing to manage the non-compliance with the technical code by deferring the XY protection relay replacement represents an increasing compliance risk as well as retaining an unfavourable safety and reliability exposure on Power and Water's most critical transmission assets over a period where the stability of the Power and Water system is expected to come under significant pressure from increased renewables, storage and more extreme intraday changes in the location of generation and subsequent power flows.

4 Recommendation

The recommended option is Option 2 - Targeted replacement and repair at an estimated cost of $10.3 million (real 2021/22) to be most prudent and cost effective to meet the identified needs.

The proposed program is consistent with the NT National Electricity Rules Capital Expenditure Objectives as the expenditure is required to maintain the quality, reliability, and security of supply of standard control services and maintain the safety of the distribution system.

This option mitigates the increasing risks arising from obsolescence, non-compliance with technical code requirements and withdrawal of manufacturer support, whilst retaining recovered units in spares to serve as emergency spares to mitigate reliability impacts as the obsolete relays are transitioned off the network over time.

Alternative options to manage the risk posed by operating obsolete relays were considered less preferable on the basis that:

- any prudent 'run-to-failure' strategy must be supported by appropriate spares holdings (usually relying on reclaimed units). Every replacement of a unit under this strategy will deplete the spares adequacy and increase the risk to the business– this is far more acute in small populations such as the Power and Water asset base than in much larger networks.
- without like-for-like replacement units held as spares, individual replacements with modern units would typically involve panel modifications to accommodate the newer units, as well as recording and communications equipment to support modern relay functionality. This would generally extend the length of outages and volume of unplanned work to return the assets to service.
- a more aggressive planned replacement program would result in higher costs over the next regulatory period due to the larger scope of work involved (frequently addressed by substation for networks with much higher volumes of energy at risk). The lower volumes of energy at risk in the Power and Water system is insufficient to justify more aggressive replacement plans.

Considering the small scale of Power and Water's relay population, existing management of end-of-life relays through staged retirement (and interim reclaimed spares support) to prudently mitigate the cost to customers of transitioning more quickly to new relay technologies is considered to be appropriate.

The additional data recording, control and reporting functionality will support the businesses 'future network' strategy by allowing more detailed analysis, control and monitoring of network conditions to support renewables and storage integration and orchestration within dynamic network operating constraints.

The implementation of integrated protection settings management software mitigates a range of credible system transition risks such as duplicated system studies due to outdated (or otherwise unverified/audited) protection settings or over constraint of renewables, DER and storage.

4.1 Strategic alignment

The "Power and Water Corporation Strategic Direction" is to meet the changing needs of the business, our customers and is aligned with the market and future economic conditions of the Northern Territory projected out to 2030.

This proposal aligns with Asset Management System Policies, Strategies and Plans that contributes to the D2021/260606 "PWC Strategic Direction" as indicated in the table below.

Table 7 Alignment with corporate strategic focus areas

	Strategic direction focus area	Strategic direction priority
1	Customer and the community at the centre	Improve Public Health and Safety
2	Always Safe	Cost Prudency

The primary concern with obsolete and non-compliant relays is the impact on safety and reliability in the event of a failed or false operation of protection devices, particularly at a distribution level where there is not a code requirement for duplicated and fully independent protection schemes.

The replacement of the obsolete and non-compliant relays will enable the risks associated with older technology to be managed off the network, whilst the replacement assets will capture the data and provide control functionality that will allow Power and Water to better understand network performance under unusual events and consider potential protection settings optimisation/scheme co-ordination to reliably accommodate more customer and community energy resources on the power system.

4.2 Dependent projects

There are no known projects or other network issues that are dependent on the resolution of this network issue.

The replacement requirements for obsolete relays are co-ordinated with network planning for replacement or augmentation across sites to access synergies in delivery. Importantly, the improved data recording, analysis and control capability of the modern relays will allow for more nuanced analysis of system operations under unusual conditions – allowing a better understanding of the conditions and protection settings which can allow for more distributed energy resources, large scale storage or utility scale solar to serve the NT power system.

This is complementary to Power and Water's 'future network' strategy which will improve the ability for customer and third party generation and storage assets to meet the changing needs of Territorians as the power system transitions to much lower carbon operations by 2030.

4.3 Deliverability

Power and Water is delivering on a similar sized protection relay replacement program for the current regulatory period. The proposed protection relays replacement volume is only slightly larger for the 2024-29 regulatory period.

As a standard program of works, Power and Water is confident that the scope of works can be delivered based on historical practices and resources available.

Consideration has been given to the demand for specialist skills in the development of this program, specifically the demand for the specialist technical skills for relay replacement in older substation panels. The proposed program reflects a relay replacement volume for obsolete relays and work to address non-compliant relays that is expected to align with expected longer term labour availability.

The long term planning for the removal of obsolete and unsupported static relay technologies over the next few regulatory periods will consider the long term resourcing risks within the specialist secondary systems workforce. There will be more upward pressure on relay replacement volumes as more static and early microprocessor-based relays reach the end of their support life.

4.4 Customer considerations

As required by the AER's Better Resets Handbook, in developing this program Power Services has taken into consideration feedback from its customers.

Feedback received through customer consultation undertaken at the time of writing this business case, has demonstrated strong support amongst the community for appropriate expenditure to enable long term maintenance of the network to ensure continued reliability, maintainability and safety of supply.

4.5 Expenditure profile

Table 7 show a summary of the expenditure requirements for the 2024-29 regulatory period.

Table 8 Annual capital and operational expenditure ($'000, real 2021/22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	2,784	1,323	2,352	2,064	1,754	10,277
Opex	-	-	-	-	-	-
Total	**2,784**	**1,323**	**2,352**	**2,064**	**1,754**	**10,277**

4.6 High-level scope

The scope of the relay replacement program is summarised in the tables below., with the corresponding number of units and total expenditure.

Table 9 Expenditure by scope item ($,000 real 2021/22)

Item	Units	Total
Obsolete relay replacement	[redacted]	[redacted]
Fault recording	[redacted]	[redacted]
Non-compliant scheme replacement	[redacted]	[redacted]
Protection setting Management software	[redacted]	[redacted]
Unplanned replacement	3	246
Total		**10,277**

Additional detail as to the individual protection relays and related devices, and the basis for the cost estimate is provided in Appendix B.

Reporting requirements for System Control

The reporting requirements for System Control are outlined below.

"The Power System Controller is required under clause 7.3.2 of the SCTC to determine whether a power system incident is a reportable incident and if determined to be a reportable incident, classify the reportable incident as either:

- *a major reportable incident; or*
- *a minor reportable incident.*

The Power System Controller, in classifying a reportable incident, will be guided by good electricity industry practice and the objectives of the SCTC, the Network Technical Code (NTC) and the Secure System Guidelines.

The identification/classification process encompasses the following daily actions undertaken by the Power System Controller:

- *The electronic logging of power system incidents in real time;*
- *Automatic daily reporting (Daily Report) of the logged power system incidents from the previous day;*
- *Identification of reportable incidents from the Daily Report by System Control which includes limited reportable incident data collection; and,*
- *Classification of reportable incidents"* [11]

The network business, as a key system participant, is required to meet the reporting obligations within the timeframes outlined in the guidelines. As part of the Final Incident Reporting, the Root Cause Analysis of the Protection Relay Data is highlighted as a key input to the investigation, including:

- *"… protection relays settings, active elements and if available relay graphical data for the reportable incident. A protection investigation must include (where applicable)*
- *Protection operation (as designed, expected or otherwise);*
- *Protection recommendations or improvements;*
- *Any other findings or conclusions*[12]

[11] PowerWater, *Power System Incident Reporting* Guideline Version 0.1 D2021/15497 p.6.
[12] PowerWater, *Power System Incident Reporting* Guideline Version 0.1 D2021/15497 p.9.

Appendix A. Cost estimation

A.1. Asset costs

The cost estimate for protection relay replacement was based on a bottom up build using the updated labour rate for field crew and a detailed breakdown of the tasks required for each relay type. The existing type of relay and the replacement type as this impacts the additional works required to physically install it and connect it electrically.

The items considered in the build up were:

- **Substation services:** this includes the work required for physical installation of the relay, including if the relay can be installed in an existing panel or if it requires a new panel and decommissioning costs. This was estimated based on hours required and labour rate.
- **Test and protection:** the cost to test the relay once installed to ensure correct operation. This was estimated based on hours required and labour rate.
- **SCADA:** the cost of connecting the relay to SCADA, on the basis that the SCADA RTU on site is compliant with the current Power Services standards.
- **Settings and configuration:** this includes the panel design, wiring design, protection studies and relay configuration. This was estimated based on hours required and labour rate.
- **Drawing and secondary design:** covers the cost of new drawing and updating old drawing to 'As Built' status.
- **Miscellaneous items:** this is an allowance for minor items required during the installation and commissioning, such as DIN Rail, fuses etc.

The relay cost was then multiplied by the number of assets to be replaced of each type to build up the total cost.

A.2. Obsolete Relays

The program addresses the following 61 obsolete relays across the Power and Water network.

Table 10 Scope of Obsolete Relay Program

ZSS	Voltage	Type	Age[1]	Reason	[redacted]	Year
Archer	66 kV	Distance	9	Obsolescence / Functionality	[redacted]	2027/28
Batchelor	22 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Batchelor	22 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Batchelor	22 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Batchelor	22 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	

Channel Island	132 kV	Timer Pickup	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Timer Pickup	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Synch Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Timer Pickup	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	HiZ Bus Diff	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Timer Pickup	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Synch Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Timer Pickup	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Synch Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	HiZ Bus Diff	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	HiZ Bus Diff	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Synch Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	

Channel Island	132 kV	IOC	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	CBF Check	36	Obsolescence / No support	[redacted]	
Channel Island	132 kV	Synch Check	36	Obsolescence / No support	[redacted]	
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Frances Bay	11 kV	OCEF	12	Obsolescence / No support	[redacted]	2028/29
Hudson Creek	66 kV	Distance	35	Obsolescence / Functionality	[redacted]	2027/28
Hudson Creek	66 kV	Synch Check	35	Obsolescence / No support	[redacted]	
Hudson Creek	66 kV	CBF	10	Obsolescence / No support	[redacted]	
Hudson Creek	66 kV	Sync Check Timer		Obsolescence / No support	[redacted]	
Hudson Creek	66 kV	Timer Pickup		Obsolescence / Functionality	[redacted]	
Love Groove	11 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Love Groove	11 kV	OCEF	13	Obsolescence / No support	[redacted]	2028/29
Mitchell Street SS	11 kV	OCEF	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	SEF	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	OC	36	Obsolescence / No support	[redacted]	

Mitchell Street SS	11 kV	ARC	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	OCEF	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	OCEF	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	Pilot Diff	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	Pilot Current	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	UV	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	Synch Check	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	UV	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	Pilot Diff	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	Pilot Current	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	SEF	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	OCEF	36	Obsolescence / No support	[redacted]	
Mitchell Street SS	11 kV	ARC	36	Obsolescence / No support	[redacted]	2025/26
Mitchell Street SS	11 kV	OCEF	36	Obsolescence / No support	[redacted]	2027/28
Palmerston	11 kV	OCEF	5	Condition / Functionality/Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	27	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	11	Condition / Functionality/ Obsolescence	[redacted]	2024/25

Palmerston	11 kV	OCEF	9	Condition / Functionality /Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	7	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	7	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	27	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	11	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	9	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	9	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11 kV	OCEF	11	Condition / Functionality/ Obsolescence	[redacted]	2024/25

Palmerston	11 kV	OCEF	5	Condition / Functionality/ Obsolescence	[redacted]	2024/25
Palmerston	11kV	Bus Diff		Obsolescence / Functionality/Enhance functionality/ Safety	[redacted]	2024/25
Weddell	66 kV	OCEF	14	Obsolescence / No support	[redacted]	2028/29
Weddell	66 kV	OCEF	14	Obsolescence / No support	[redacted]	2028/29
Total					[redacted]	

Note 1: The age of the asset is shown as at 2021

A.3. Fault Recorder compliance

Table 11 Scope of Data Recorder Compliance Program

ZSS	CB ID	Voltage Level	Type	Yr	Age	Reason for Installation	[redacted]	Year
Katherine		11kV		New		functionality	[redacted]	27/28
Strangways		11kV		New		functionality	[redacted]	27/28
Archer		22kV		New		functionality	[redacted]	27/28
Sadadeem		11kV		New		functionality	[redacted]	26/27
Love Groove		22kV		New		functionality	[redacted]	26/27
Woolner		11kV		New		functionality	[redacted]	26/27
DA Zone		11kV		New		functionality	[redacted]	27/28
Casaurina		11kV		New		functionality	[redacted]	27/28
Total							[redacted]	

A.4. Non-Compliant 66kV Protection scheme

The X-Y Protection Relay replacement program addresses the historical non-compliance with the Network technical Code requirements for independent duplicated protection schemes at 66kV and above by replacing the following 8 protection relays.

Table 12 Scope of X-Y Protection Relay Compliance Program

ZSS	CB ID	Voltage Level	Type	Yr	Age[1]	Reason for replacement	[redacted]	Year
Hudson Creek	pr cb 66hcbusA	66 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Hudson Creek	pr cb 66hcbusB	66 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Hudson Creek	pr cb 66hcbusC	66 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Hudson Creek	pr cb 66hcbusD	66 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Hudson Creek	pr cb 132HCbusA	132 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Hudson Creek	pr cb 132HCbusB	132 kV	HiZ Bus Diff	1987	34	Code compliance X/Y Protection	[redacted]	26/27
Channel Island	PR CB 132CIBUS	132 kV	HiZ Bus Diff	1988	33	Code compliance X/Y Protection	[redacted]	27/28
Channel Island	PR CB 132CIBUS	132 kV	HiZ Bus Diff	1988	33	Code compliance X/Y Protection	[redacted]	27/28
Total							[redacted]	

Note 1: The age of the asset is shown as at 2021

A.5. Relay failure

Historical expenditure shows an average annual cost of $98,340 (real 2021-22) per year for addressing relay failure based. Due to the significant replacement and retirement program, we have reduced this to 50% to account for the general rejuvenation of the asset fleet. This provides a total of $245,850 (real 2021-22) for the next regulatory period.

A.6. Protection Settings Management software cost

The cost estimate for the protection settings management software was based on preliminary vendor pricing advice for implementation, with an indication of the comparative scale of licencing for other Australian networks.

A project estimate of [redacted] was established for the regulatory submission based on the vendor advised costs and Power and Water's inclusions for any capital components of licencing, implementation, configuration and training, at an assumed 2021 EUR/AUD exchange rate of 0.61 EUR to 1 AUD.

The cost estimate is detailed in the table below.

Table 13 StationWare Capital Cost Estimate (real 2021/22)

Item	Qty	[redacted]	Comment
Perpetual License Cost (30 users)	30	[redacted]	From Vendor
Settings Conveters (8 + 2 free)	8	[redacted]	From Vendor
Contracted Maintenance	5	[redacted]	[redacted]
Vendor Training	6	[redacted]	6 Trainer Days @ Max 10 Users per day
Vender Trainer Travel and Accommodation	6	[redacted]	Allowance for flights and accommodation
Power and Water User Implementation/Training Costs	30	[redacted]	[redacted]
Power and Water User Project Co-ordination	6	[redacted]	PM and non Darwin staff accommodation for project
Vendor Model Building Support	1	[redacted]	Estimate confirm during vendor negotiations
Allowance for IT/OT Implementation support	1	[redacted]	Estimate confirm during vendor negotiations
Total		[redacted]	
Total (rounded)		[redacted]	

Contact

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