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Maintaining compliance with performance standards applicable to protection relays

RIT-T Project Specification Consultation Report

Issue date: 18 October 2023

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining compliance with performance standards applicable to protection relays. This RIT-T includes 419 protection relays at various locations on the ACT and NSW transmission network, based on their assessed condition. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Protection relays are used throughout the transmission network to isolate network faults and reduce their impact on system security, system reliability and network infrastructure. In this RIT-T we are examining options to address the risk of failure of individual protection relays that isolate faults on transmission lines, transformers, reactors, capacitors, and busbars (interzone). Additionally, this RIT-T includes options for addressing risks to under frequency load shedding (UFLS) schemes. These UFLS schemes at various substations on the network are designed to arrest a fall in frequency by progressively disconnecting load in a coordinated and automatic manner. These schemes are implemented to satisfy requirements set out in the National Electricity Rules (NER)[1].

The identified protection relays will reach the end of their technical life by 2027/28, with manufacturer support, access to spares and defects rates being the largest drivers for remediation. The risk of reliably protecting primary assets increases as technology becomes superseded by the manufacturer, manufacturer support ceases and spare parts become scarce.

If the condition issues on the identified assets are not addressed by 2027/28, risk of failure of the assets will increase. Table E-1 outlines the condition issues on the protection relays, the impact of those condition issues if not remediated, and the consequences if no action is taken.

Table E-1 Condition issues on protection relays on the ACT and NSW network, their potential impact, and consequences

Issue	Potential impact	Consequence
Technology obsolescence	Manufacturer support is limited or withdrawn, repair and replacement facilities are expected to be unavailable.	Assets continue to deteriorate and risk of failure increases.
Decreased function	Assets have increasing numbers of faults as they progress along their failure curves, deteriorating components or are prone to mechanical wear.	Likelihood of a hazardous event occurring increases.

Given the high population of protection relays that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program.

Identified need: meet the service level required under National Electricity Rules for protection schemes

Protection relays play a central role in supplying electricity across the ACT and NSW transmission network. Used to control, monitor, protect and secure communication to facilitate safe and reliable network

[1] As per Schedule 5.1 of the NER.

operation, protection relays are necessary to operate the transmission network and prevent damage to primary assets when adverse events occur[2].

Redundant protection schemes are required to ensure the transmission system is adequately protected as outlined in the Network Performance Requirement under Schedule 5.1 of the National Electricity Rules (NER), therefore the condition issues affecting the identified protection relays on the ACT and NSW transmission network must be addressed. The Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on Transmission Network Service Providers (TNSPs) to provide redundant protection schemes to ensure the transmission system is adequately protected. Clause 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems (including breaker fail protection systems), to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary assets where the secondary system fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also ensure that all protection systems for voltages above 66 kV are well-maintained and available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out.[3]In the event of an unplanned outage, AEMO's Power System Security Guidelines require that the primary network assets must be taken out of service within 24 hours[4].

A failure of the secondary systems would involve replacement of the failed component or taking the affected primary assets, such as lines and transformers, out of service. Though replacement of a failed secondary systems component is a possible interim measure, the approach is not sustainable as the stock of spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, interim replacements will cease to be a viable option to meet performance standards stipulated in clause 4.6.1 of the NER.

If the failure to provide functional protection schemes due to technology obsolescence is not addressed by a technically and commercially feasible credible option in sufficient time (by 2027/28), the likelihood of not recovering from secondary systems faults and not maintaining compliance with NER performance requirements will increase.

The proposed investment will enable us to continue to meet the standards for secondary systems availability set out in the NER, and to avoid the impacts of taking primary assets out of service. Consequently, it is considered a reliability corrective action under the RIT-T.

A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

2 As per Schedule 5.1 of the NER.
3 As per S5.1.2.1(d) of the NER.
4 AEMO. "Power System Security Guidelines, 9 March 2023." Melbourne: AEMO, 2023.23. Accessed 6 September 2023.

One credible network option has been identified

We have identified one credible network option that we consider would meet the identified need from a technical, commercial, and project delivery perspective.[5] The only option that meets these criteria is summarised in Table E-2.

Table E-2 Summary of credible options

Option	Description	Estimated capex ($2021-22 m)	Expected commission date
Option 1	**Renewal of individual assets**	$47.18	2024-2028
Transmission line protection relays		$33.07	
Transformer protection relays		$7.80	
Reactor protection relays		$1.78	
Capacitor protection relays		$2.71	
Busbar (and interzone) protection relays		$0.92	
Protection relays associated with UFLS schemes		$0.90	

Non-network options are not expected to be able to assist in this RIT-T

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T. Non-network options are not able to meet NER obligations to provide redundant protection schemes and ensure that the transmission system is adequately protected.

The options will be assessed against three reasonable scenarios

The credible options will be assessed under three scenarios as part of the Project Assessment Draft Report (PADR) assessment, which differ in terms of the key drivers of the estimated net market benefits (ie, the estimated risk costs avoided).

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the most likely scenario from AEMO's Integrated System Plan (ISP) (ie, the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions and have been based on Transgrid's analysis.

[5] As per clause 5.15.2(a) of the NER.

Table E-2 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario risk
Scenario weighting	1/3	1/3	1/3
Discount rate	7%	7%	7%
VCR ($2022-23)	$49,216/MWh	$49,216/MWh	$49,216/MWh
Network capital costs	Base estimate	Base estimate	Base estimate
Operating and maintenance costs	Base estimate	Base estimate	Base estimate
Environmental, safety and financial risk benefit	Base estimate	Base estimate – 25%	Base estimate + 25%
Avoided unserved energy	Base estimate	Base estimate – 25%	Base estimate + 25%

The sensitivity analysis will investigate how the NPV results are affected by changes to other variables, including the discount rate and capital costs.

Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 15 January 2024.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[6] In the subject field, please reference 'protection relays PSCR.'

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. Subject to any additional credible options being identified, we anticipate publication of a PADR by February 2024.

6 Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

Contents

1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for options for maintaining compliance with performance standards applicable to protection relays. This RIT-T includes 419 protection relays at various locations on the ACT and NSW transmission network. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Protection relays are used throughout the transmission network to isolate network faults and reduce their impact on system security, system reliability and network infrastructure. In this RIT-T we are examining options to address the risk of failure of individual protection relays that isolate faults on transmission lines, transformers, reactors, capacitors, and busbars (interzone). Additionally, this RIT-T includes options for addressing risks to protection relays associated with under frequency load shedding (UFLS) schemes. These UFLS schemes at various substations on the network are designed to arrest a fall in frequency by progressively disconnecting load in a coordinated and automatic manner. These schemes are implemented to satisfy requirements set out in the National Electricity Rules (NER)[7].

The purpose of this PSCR is to examine and consult on options to address the risk of protection relay failure due to technological obsolescence, on the ACT and NSW transmission network. As investment is intended to maintain compliance with NER requirements, we consider this a reliability corrective action RIT-T.

1.1. Purpose of this report

The purpose of this PSCR[8] is to:

- set out the reasons why we propose that action be undertaken (the 'identified need');
- present the options that we currently consider address the identified need;
- outline the technical characteristics that non-network options would need to provide (although we note that non-network options are unlikely to be able to contribute to meeting the identified need for this RIT-T);
- summarise how we intend to assess options for addressing the identified need in the Project Assessment Draft Report (PADR); and
- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

1.2. Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 15 January 2024[9].

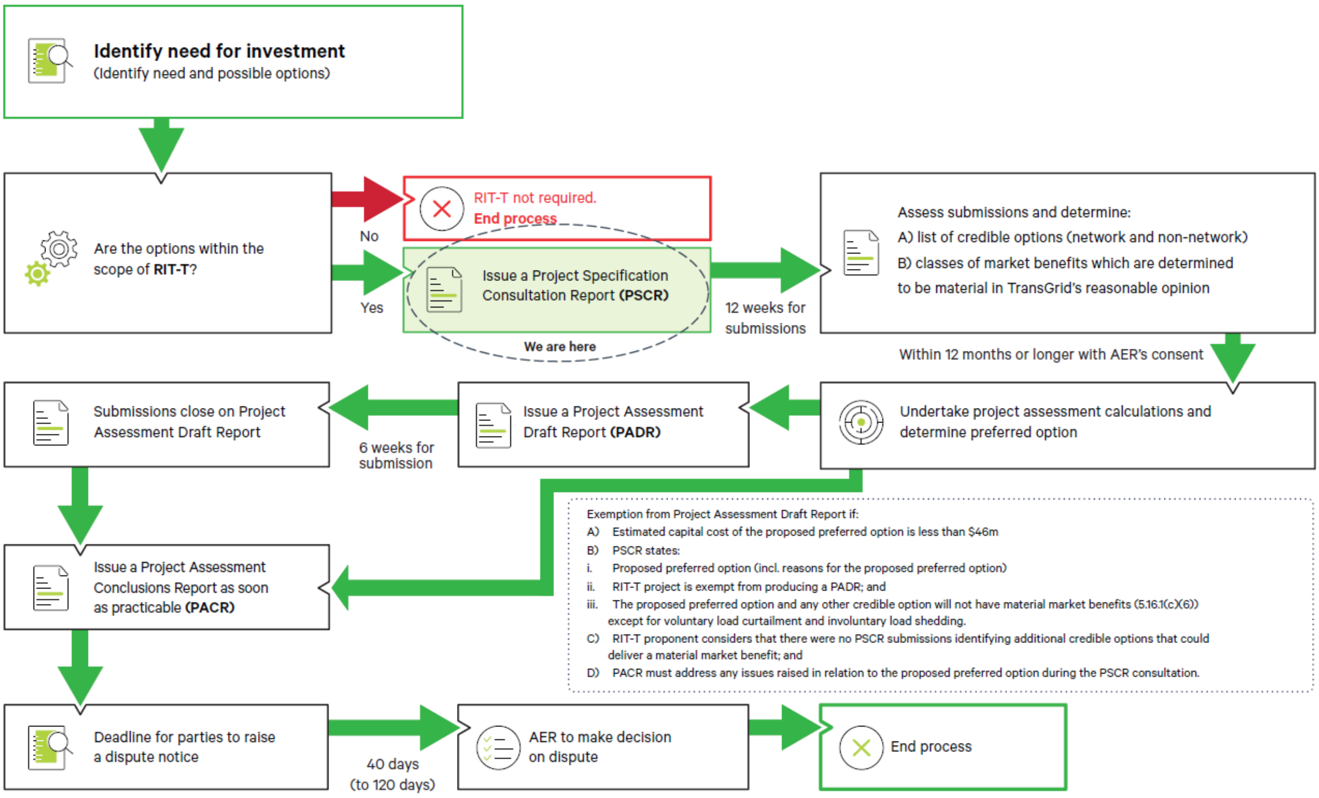
Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[10] In the subject field, please reference 'Protection relays PSCR'. At the conclusion of the consultation process,

7 As per Schedule 5.1 of the NER.
8 See Appendix A for the National Electricity Rules requirements.
9 Consultation period is for 12 weeks, additional days have been added to cover public holidays.
10 We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

Subject to additional credible options being identified during consultation, we anticipate publication of a PADR by February 2024.

Figure 1-1 This PSCR is the first stage of the RIT-T process[11]



[11] Australian Energy Market Commission. "[Replacement expenditure planning arrangements, Rule determination]". Sydney: AEMC, 18 July 2017.

2. The identified need

This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out background information related to the identified protection relays.

2.1. Background to the identified need

Protection relays are used throughout the transmission network to isolate network faults and reduce their impact on system security, system reliability and network infrastructure. In this RIT-T we are examining options to address the risk of failure of individual protection relays that isolate faults on transmission lines, transformers, reactors, capacitors, and busbars (interzone). Additionally, this RIT-T includes options for addressing risks to four under frequency load shedding (UFLS) schemes. These UFLS schemes at various substations on the network are designed to arrest a fall in frequency by progressively disconnecting load in a coordinated and automatic manner. These schemes are implemented to satisfy requirements set out in the National Electricity Rules (NER)[12].

The assets included in this RIT-T will reach the end of their serviceability by FY2027/28. Serviceability is evaluated against multiple factors including manufacturer support for repairs and replacements, historical defect rates of individual models, availability of spares and statistical probability of failure. We have identified 419 protection assets on our network that will reach the end of their serviceability by 2027/28. These assets comprise of various technologies such as electromechanical, discrete component and microprocessor-based relays. A list of the targeted devices is provided in Appendix C.

The end-of-life assets have been identified through the application of our Network Asset Health Framework based on their asset health index and effective age. The evaluated health index inputs for protection assets considers multiple factors including manufacturer support for repairs and replacements, historical defect rates of individual models, availability of spares and statistical probability of failure.

A protection relay failing to operate during a network fault would result in a catastrophic failure of the primary asset, placing a burden on the connected busbar. This would then cause a cascading failure on the connected bus, nearby transformers and transmission lines. The failure of the surrounding assets would be the only feasible way to trigger another active protection scheme. This would then be a matter of either the generators tripping or further surrounding assets failing.

2.2. Description of identified need

Protection relays control, monitor, protect and secure communication to facilitate safe and reliable network operation and to prevent damage to primary assets when adverse events occur[13].

Redundant protection schemes are required to ensure the transmission system is adequately protected as outlined in the Network Performance Requirement under Schedule 5.1 of the National Electricity Rules (NER), therefore the condition issues affecting the identified protection relays on the ACT and NSW transmission network must be addressed. The Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on Transmission Network Service Providers (TNSPs) to provide redundant protection schemes to ensure the transmission system is adequately protected. Clause 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems (including

[12] As per Schedule 5.1 of the NER.
[13] As per Schedule 5.1 of the NER.

breaker fail protection systems), to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary assets where the secondary system fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also ensure that all protection systems for voltages above 66 kV are well-maintained and available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out.[14] In the event of an unplanned outage, AEMO's Power System Security Guidelines require that the primary network assets must be taken out of service within 24 hours[15].

A failure of the secondary systems would involve replacement of the failed component or taking the affected primary assets, such as lines and transformers, out of service. Though replacement of a failed secondary systems component is a possible interim measure, the approach is not sustainable as the stock of spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, interim replacement will cease to be a viable option to meet performance standards stipulated in clause 4.6.1 of the NER.

If the failure to provide functional protection schemes due to technology obsolescence is not addressed by a technically and commercially feasible credible option in sufficient time (by 2027/28), the likelihood of not recovering from secondary systems faults and not maintaining compliance with NER performance requirements will increase.

The proposed investment will enable us to continue to meet the standards for secondary systems availability set out in the NER, and to avoid the impacts of taking primary assets out of service. Consequently, it is considered a reliability corrective action under the RIT-T.

A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

Given the high population of protection relays that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program.

2.3. Assumptions underpinning the identified need

We adopt a risk cost framework to quantify and evaluate the risks and consequences of increased failure rates. Appendix B provides an overview of our Risk Assessment Methodology.

We note that the risk cost estimating methodology aligns with that used in our recently submitted Revised Revenue Proposal for the 2023-28 period. It reflects feedback from the Australian Energy Regulator (AER) on the methodology initially proposed in our initial Revenue Proposal.

Figure 2-3 summarises the increasing risk costs over the under the base case and our central scenario of asset failure risk.

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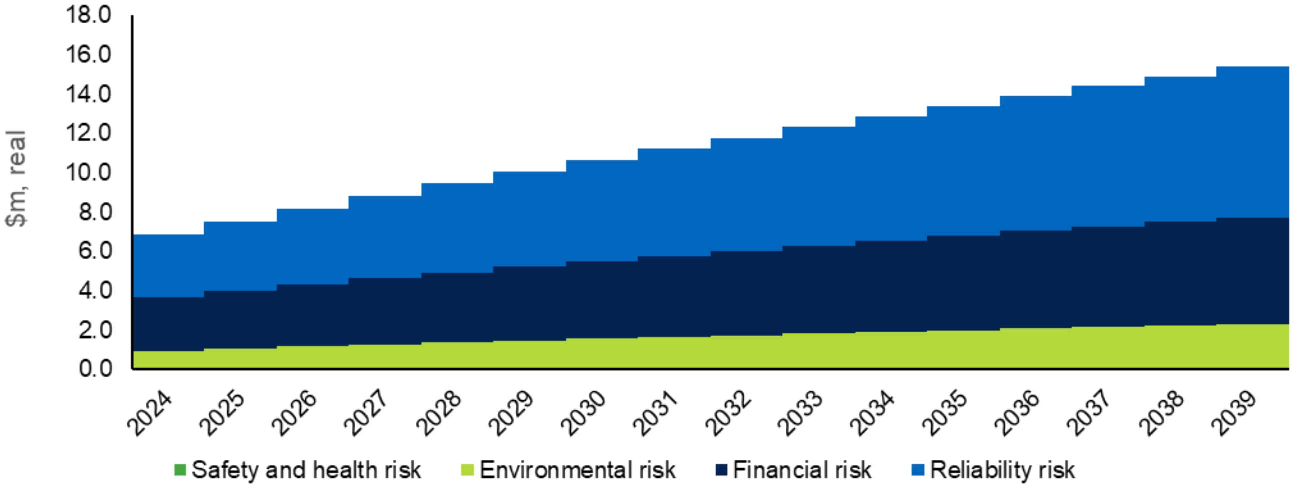
[14] As per S5.1.2.1(d) of the NER.

[15] AEMO. "Power System Security Guidelines, 9 March 2023." Melbourne: AEMO, 2023.23. Accessed 6 September 2023. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf

Figure 2-3 Estimated risk costs under the base case (central scenario)



This section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. The aggregate risk cost under the base case is currently estimated at around $6.84 million in 2023/24, and it is expected to increase going forward if action is not taken (reaching approximately $15.41 million in 2038/39 by the end of the 15-year assessment period).

2.3.1. Asset health and the probability of failure

The health index score for a protection relay is dependent on the asset serviceability factors outlined below.

Spares and Support: Due to the proprietary nature of protection assets, an evaluation of manufacturer support and/or spares availability is critical for ensuring the continuing operability of these assets. This figure represents the ability to repair or replace an in-service failed asset.

Historical defect rates: A key factor into asset health is the historical rate of defects experienced across individual models. A 3-year average is utilised to minimise bias to peaks and troughs. This figure represents the potential underlying issues with a particular model.

Asset type: The type of technology on which the asset is based affects the overall health index of the asset. Older technologies such as electromechanical and discrete component assets suffer from degradation over time, being effectively mechanical devices. These also lack self-monitoring capabilities and as such can fail between maintenance testing cycles. Modern microprocessor-based devices do not suffer from degradation in a similar manner and have the ability to self-monitor and alarm on failure (watchdog).

Natural age: A protection asset's natural age is calculated from its first install date. This age contributes to the overall health index.

2.3.2. Reliability risk

The risk of unserved energy for customers following a failure of the protection relays identified in this PSCR will be assessed in the NPV analysis presented in the PADR. The likelihood of a consequence considers the likelihood of duplicated protection failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit, the anticipated load restoration time (based on the expected time to undertake repair), and the load at risk (based on forecast demand). The monetary value is based on an assessment of the value of lost load, which measures the economic impact to affected customers of a disruption to their electricity supply.

Unit protection is an industry standard whereby protection schemes are limited in their range of cover to only those protected assets. This approach maximises system security by mitigating the risk of false trips due to adjacent equipment conditions.

Adjacent protection schemes cannot detect faults outside their protection zone when unit protection is implemented. Reliable protection operation is achieved through the duplication of protection schemes.

As outlined in our [Network Asset Criticality Framework](), we have undertaken quantification of the reliability consequence of an uncleared fault on the ACT and NSW 500 kV and 330 kV network. The impact of an uncleared or slow-to-clear fault is one of the main risks presented by Transgrid's protection systems to the primary transmission 500 kV and 330 kV network. The consequence of this risk can vary dramatically depending on a complex array of variables; the extreme result being a 'Black Start' – that is, the de-energisation of the entire ACT and NSW transmission network.

We have analysed the performance of protection schemes at voltage levels of 220kV and below. The analysis determined that an uncleared fault would result in the associated busbar effectively becoming a fuse to assist in a consistent analysis, the reliability consequence for these assets is calculated as the loss of load of the site associated with the failed protection element.

2.3.3. Safety risk

This refers to the safety consequence to staff, contractors and/or members of the public of an asset failure. The likelihood of a consequence considers the likelihood of duplicated protection also failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit. For protected assets within the boundary of a site, we consider the frequency of workers on-site, duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. For protected assets outside the boundary of a site (typically transmission lines), we consider the probability of the public within the vicinity of those assets, The monetary value considers the cost associated with fatality or injury compensation, loss of productivity, litigation fees, fines and any other related costs.

2.3.4. Environmental risk

This refers to the environmental consequence (including bushfire risk) to the surrounding community, ecology, flora and fauna of an asset failure. The likelihood of a consequence considers the duplicated protection also failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit the location of the site and sensitivity of surrounding areas, the volume and type of contaminant, the effectiveness of control mechanisms, and the likelihood and impact of bushfire. The monetary value considers the cost associated with damage to the environment including compensation, clean-up costs, litigation fees, fines and any other related costs.

2.3.5. Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence considers duplicated protection also failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit. The monetary value considers the cost of replacement or repair of the failed asset and the protected asset, including any temporary measures.

3. Options that meet the identified need

We consider credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective[16]. This will include any credible options that are put forward by proponents in response to this PSCR.

We have identified one network option that we consider will meet the identified need for this RIT-T, as summarised in Table 3-1 below.

Table 3-1 Summary of the credible options

Option	Description	Estimated capex ($2021-22 m)	Expected commission date
Option 1	**Renewal of individual assets**	$47.18	2024-2028
Transmission line protection relays		$33.07	
Transformer protection relays		$7.80	
Reactor protection relays		$1.78	
Capacitor protection relays		$2.71	
Busbar (and interzone) protection relays		$0.92	
Protection relays associated with UFLS schemes		$0.90	

While we have provided indicative cost estimates for the credible options, more accurate figures may be used for the cost-benefit analysis in the PADR.

3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PSCR compares the costs and benefits of each credible option to a 'do nothing' base case. The base case is the (hypothetical) projected case if no action is taken i.e.[17]

> "*The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented.*"

Under the base case, no investment is undertaken to replace existing protection relays that are reaching end of life. These assets will continue to be maintained under the current regime and will operate until they

[16] As per clause 5.15.2(a) of the NER.
[17] AER, Regulatory Investment Test for Transmission Application Guidelines, August 2020, p.21.

fail. The annual routine operating, and maintenance is expected to cost $13,351 each year from 2023/24 to 2038/39.

The condition of the protection relays that have been identified for replacement under this program will lead to an increase in unplanned outages as the assets continue to deteriorate and age and increase the probability of not clearing a fault in the transmission network. Their failure will directly impact primary assets, such as lines, transformers and reactive plant, as they will be out of service for longer periods. This is expected to result in unserved energy of approximately 68 MWh in 2023/24 and 166 MWh in 2038/39[18]It will also lead to higher safety, environmental, and financial risk costs, that are caused by the failure of protection assets to operate when required.

The aggregate risk cost under the base case is currently estimated at around $6.84 million in 2023/24, and it is expected to increase going forward if action is not taken (reaching approximately $15.41 million by the end of the 15-year assessment period).

3.2. Option 1 – Renewal of individual assets

Option 1 involves individual replacements of 419 identified assets (listed in Appendix C) across 48 sites within the regulatory period. The option is based on a like-for-like approach whereby the asset is replaced by its modern equivalent. Additional system modifications or additional functionalities would not be deployed under this option.

This option would deliver risk mitigation and reduced corrective maintenance benefits to consumers and the networks by only targeting the probability of failure of identified assets. This option will not deliver any additional operational benefits such as improved capabilities for remote interrogation and predictive activities.

This option will phase asset renewals across the regulatory control periods. Deployments are prioritised based on investment benefit with consideration also given to efficient delivery strategies. Targeted assets will be in service for approximately 15 years, with some assets remaining at each site to incur investment in future years.

The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. The capital cost of this option is approximately $47.18 million (in $2021-22). The table below provides a breakdown of the estimated capital cost. In addition, routine operating and maintenance costs are estimated at approximately $13,351 per annum (in $2021-22). We expect that the protection relays will have an asset life of 15 years.

Table 3-1 Option 1 Capital Cost ($2021-22 m)

Capital cost	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Option 1	9.44	9.44	9.44	9.44	9.44	47.18

All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

Following the implementation of Option 1, the costs associated with reliability, safety, environmental and financial risks are significantly reduced. A reduction in the rate of failure of the relevant protection relays will

[18] Yearly figures for unserved energy

reduce expected unserved energy and the costs of emergency repair and replacements. A reduction in the risk of explosive failure will reduce the risk of injury to nearby people and infrastructure.

We have estimated that total risk costs under Option 1 will be approximately $4.92m in 2027/28, after all identified protection relays have been replaced (in $2021-22).

3.3. Options considered but not progressed

We considered several additional options to meet the identified need in this RIT-T. Table summarises the reasons the following options were not progressed further.

Table 3-1 Options considered but not progressed

Description	Reason(s) for not progressing
Secondary systems renewal	This option would have required the complete renewal of all secondary systems assets at each site with targeted assets. The condition of remaining assets at identified sites did not warrant additional expenditure. Therefore, this option is not commercially feasible and does not represent optimal expenditure for electricity consumers.
Refurbishment of individual assets	This option is not technically feasible due to the specialised skillsets required and the inability to resolve the lack of support from manufacturers.
Asset retirement	This can only be achieved through retirement of the associated primary assets, which is not technically or commercially feasible.
Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection.

3.4. No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[19] A 'material inter-network impact' is defined in the NER as:

> *"A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."*

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:[20]

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and

[19] As per clause 5.16.4(b)(6)(ii) of the NER.

[20] Inter-Regional Planning Committee. *"Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations."* Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 14 May 2020. https://www.aemo.com.au/-/media/Files/PDF/170-0035-pdf

- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We note that each credible option satisfies these conditions as it does not modify any aspect of electrical or transmission assets. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with any of the credible options considered.

4. Non-network options

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T. Secondary systems are fundamentally about enabling the safe and reliable control and operation of Transgrid's network assets, and there are currently no known non-network alternatives that can effectively augment or substitute for the investments that Transgrid is proposing.

Irrespective of technical characteristics such as the size of load reduction of additional supply, location and operating profile, we do not consider that non-network options can meet regulatory obligations under Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

5. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the National Electricity Rules (NER) and whether they are considered material for this RIT-T.[21]

5.1. Wholesale electricity market benefits are not material

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[22]

The credible option considered in this RIT-T will not address network constraints between competing generating centres and are therefore not expected to result in any change in dispatch outcomes and wholesale market prices. We therefore consider that the following classes of market benefits are not material for this RITT assessment:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- changes in network losses;
- competition benefits; and
- Renewable Energy Target (RET) penalties.

5.2. No other classes of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(6) requires that we consider the following classes of market benefits, listed in

Table , arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons in

Table .

Table 5-1 Reasons non-wholesale electricity market benefits are considered immaterial

[21] The NER requires that all classes of market benefits identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or classes) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.15A.2(b)(6). See Appendix A for requirements applicable to this document.

[22] Australian Energy Regulator. "*Application guidelines Regulatory Investment Test for Transmission - August 2020.*" Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf

Market benefits	Reason
Changes in involuntary load shedding	A failure of any single secondary system element results in an extremely low chance of unserved energy.
Differences in the timing of expenditure	The credible options considered are unlikely to affect decisions to undertake unrelated expenditure in the network. Consequently, material market benefits will neither be gained nor lost due to changes in the timing of other network expenditure from any of the options considered.
Option value	We note the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[23] We also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. We note that no credible option is sufficiently flexible to respond to change or uncertainty for this RIT-T. Specifically, each option is focused on proactively replacing deteriorating assets ahead of when they fail.

[23] Australian Energy Regulator. "*Application guidelines Regulatory Investment Test for Transmission - August 2020.*" Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf

6. Overview of the assessment approach

This section outlines the approach that we have applied in assessing the net benefits associated with each of the credible options against the base case.

6.1. Description of the base case

Under the base case, no investment is undertaken to replace existing protection relays that are reaching end of life. These assets will continue to be maintained under the current regime and will operate until they fail.

The condition of the protection relays that have been identified for replacement under this program will lead to an increase in unplanned outages as the assets continue to deteriorate and age and increase the probability of not clearing a fault in the transmission network. Their failure will directly impact primary assets, such as lines, transformers and reactive plant, as they will be out of service for longer periods. This is expected to result in unserved energy of approximately 68 MWh in 2023/24 and 166 MWh in 2038/39.[24]It will also lead to higher safety, environmental, and financial risk costs, that are caused by the failure of protection assets to operate when required.

We note that this course of action is not expected in practice. However, this approach has been adopted since it is consistent with AER guidance on the base case for RIT-T applications[25].

6.2. Assessment period and discount rate

A 15-year assessment period from 2023/24 to 2038/39 has been adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of the options.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period.

A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis that will be presented in the PADR, consistent with AEMO's Inputs Assumptions and Scenarios Consultation Report[26] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[27] The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the

[24] Yearly figures for unserved energy

[25] The AER RIT-T Guidelines state that the base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. The AER define 'BAU activities' as ongoing, economically prudent activities that occur in the absence of a credible option being implemented. (See: AER, Application guidelines Regulatory Investment Test for Transmission, August 2020)

[26] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

[27] AEMO, *2022 Integrated System Plan, June 2022*, p 91.

results to a lower bound discount rate of 3 per cent.[28] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[29]

6.3. Approach to estimating option costs

We have estimated the capital costs of the options based on the scope of works necessary together with costing experience from previous projects of a similar nature.

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).[30]

We estimate that actual costs will be within +/- 25 per cent of the central capital cost estimate. An accuracy of +/-25 per cent for cost estimates is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in real, 2021-22 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

Routine operating and maintenance costs are based on works of similar nature. Given that there is an incremental routine operating and maintenance costs saving in the options compared to the base case, this is a net benefit in the assessment.

6.4. Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER[31]. The options considered involve the replacement of capacitor banks across our network. As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options.

6.5. The options will be assessed against three reasonable scenarios

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

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[28] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Transgrid) as of the date of this analysis, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2023%E2%80%9328/final-decision

[29] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

[30] For further detail on our cost estimating approach refer to section 7 of our Augmentation Expenditure Overview Paper submitted with our 2023-28 Revenue Proposal.

[31] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124.

The credible options will be assessed under three scenarios as part of the PADR assessment, which differ in terms of the key drivers of the estimated net market benefits (ie, the estimated risk costs avoided).

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios implicitly assume the most likely scenario from the 2022 ISP (ie, the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs and unserved energy, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions, and have been based on Transgrid's analysis, as discussed in section 2.

We developed the Central Scenario around a static model of demand scenarios, described further in Section A.3 of our Network Asset Criticality Framework. We consider that this approach is appropriate since it materially reduces the computational effort required, and since differences in demand forecasts will not materially affect the ranking of the credible options.

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) will be investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).[32],[33],[34]

Table 6-1 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario risk
Scenario weighting	*1/3*	*1/3*	*1/3*
Discount rate	7%	7%	7%
VCR ($2022-23)	$49,216/MWh	$49,216/MWh	$49,216/MWh
Network capital costs	Base estimate	Base estimate	Base estimate
Operating and maintenance costs	Base estimate	Base estimate	Base estimate
Environmental, safety and financial risk benefit	Base estimate	Base estimate – 25%	Base estimate +25%
Avoided unserved energy	Base estimate	Base estimate – 25%	Base estimate +25%

We have weighted the three scenarios equally given there is nothing to suggest an alternate weighting would be more appropriate.

6.6. Sensitivity analysis

In addition to the scenario analysis, we will consider the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity testing.

[32] AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, pp. 40-41.

[33] We consider the approach to scenarios and sensitivities to be consistent with the AER guidance provided in November 2022 in the context of the disputes of the North West Slopes and Bathurst, Orange and Parkes RIT-Ts. See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 18-20 & 31-32, as well as with the AER's RIT-T Guidelines.

[34] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123-124

The range of factors tested as part of the sensitivity analysis in the PADR will include:

- lower and higher assumed capital costs;
- lower and higher estimated safety, environmental and financial risk benefits; and
- alternate commercial discount rate assumptions.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

In addition, we will seek to identify the 'boundary value' for key variables beyond which the outcome of the analysis would change, including the amount by which capital costs would need to increase for the preferred option to no longer be preferred.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 203.

Rules clause	Summary of requirements	Relevant section
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	–
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	4[35]
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3 & 5

[35] There are no credible non-network options

5.16.4(z1)	A RIT-T proponent is exempt from [preparing a PADR] (paragraphs (j) to (s)) if: 1. the estimated capital cost of the proposed preferred option is less than $35 million[36] (as varied in accordance with a cost threshold determination); 2. the relevant Network Service Provider has identified in its project specification consultation report: (i) its proposed preferred option; (ii) its reasons for the proposed preferred option; and (iii) that its RIT-T project has the benefit of this exemption; 3. the RIT-T proponent considers, in accordance with clause 5.15A.2(b)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4) except those classes specified in clauses 5.15A.2(b)(4)(ii) and (iii), and has stated this in its project specification consultation report; and 4. the RIT-T proponent forms the view that no submissions were received on the project specification consultation report which identified additional credible options that could deliver a material market benefit.	8

[36] Varied to $46m based on the AER Final Determination: Cost threshold review November 2021.4. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

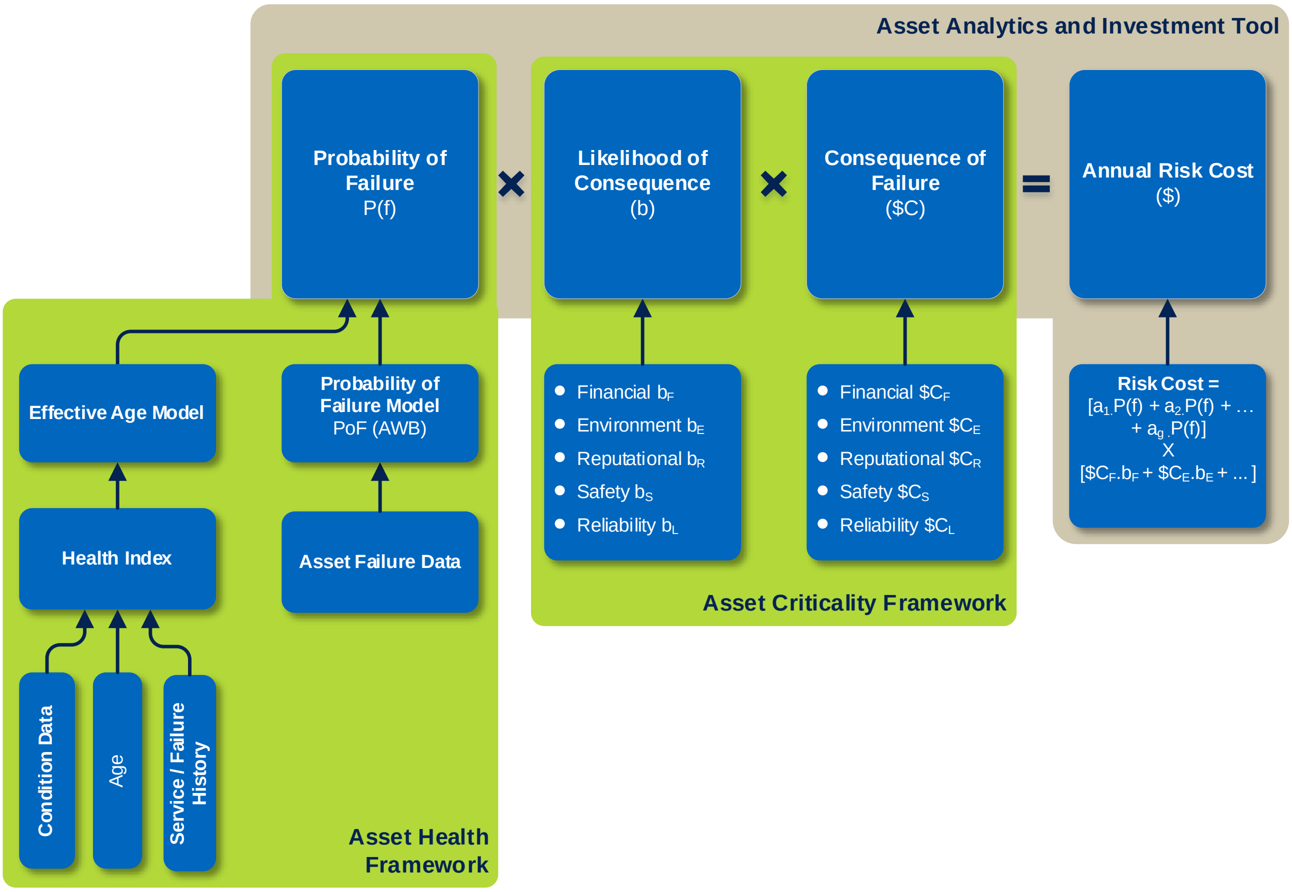
Appendix B Risk Assessment Methodology

Summary of methodology

This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline.[37]

A fundamental part of the risk assessment methodology is calculating the annual 'risk costs' or the monetised impacts of the reliability, safety, bushfire, environmental and financial risks. The monetary value of risk (per year) for an individual asset failure resulting in an undesired outcome, is the likelihood (probability) of failure (in that year with respect to its age), as determined through modelling the failure behaviour of an asset (Asset Health), multiplied by the consequence (cost of the impact) of the undesired outcome occurring, as determined through the consequence analysis (Asset Criticality). Figure B-1 illustrates the basic risk equation that we apply.

Figure B-1 Risk cost calculation



Economic justification of repex to address an identified need is supported by risk monetised benefit streams, to allow the costs of the project or program to be assessed against the value of the avoided risks

[37] Industry practice application note - Asset replacement planning, AER January 2019

and costs. The major quantified risks we apply for repex justifications include asset failures that materialise as:

- Bushfire risk;
- Safety risk;
- Environmental risk;
- Reliability risk; and
- Financial risk.

The risk categories relevant to this RIT-T are explained in Section 0.

Further details are available in our [Network Asset Risk Assessment Methodology].

Asset health and probability of failure

The first step in calculating the PoF of an asset is determining the asset health and associated effective age,[38] which considers that:

- an asset consists of different technologies, each with a particular capability, underlying reliability, life expectancy and remaining life - the overall health of an asset is a compound function of all of these attributes;
- key asset condition measures and failure data provides vital information on the current health of an asset, where the 'current effective age' is derived from asset information and condition data;
- the future health of an asset (health forecasting) is a function of its current health and any factors causing accelerated (or decelerated) degradation or 'age shifting' of one or more of its components – such moderating factors can represent the cumulative effects arising from continual or discrete exposure to unusual internal, external stresses, overloads and faults; and
- 'future effective age' is derived by moderating 'current effective age' based on factors such as, external environment/influence, expected stress events and operating/loading condition.

The PoF is the likelihood that an asset will fail during a given period resulting in a particular adverse event, e.g., equipment failure, pole failure, broken overhead conductor.

The outputs of the PoF calculation are one or more probability of failure time series which provide a mapping between the effective age, discussed above, and the yearly probability of failure value for a given asset class. This analysis is performed by generating statistical failure curves, normally using Weibull analysis, to determine a PoF time series set for each asset that gives a probability of failure for each further year of asset life. This establishes how likely it is that the asset will fail over time.

The Weibull parameters which represent the probability of failure curve for key transmission line components are summarised in

Table B-1 below.

[38] Apparent age of an asset based on its condition.

Official

Further details are available in our Network Asset Health Methodology.

Table B-1 Weibull parameters for asset components

Asset component	Weibull parameters	
	η	β
Multifunction Intelligent Electronic Device: • Protection • Controller • Telecommunication	14.3	1.78
Protection Relay - Solid State	32.7	1.24
Protection Relay - Electromechanical	92.9	1.57

Appendix C Protection relays identified for replacement

The table below details the protection relays identified by this need under the preferred option (Option 1).

Table C-2 Protection relays identified for this RIT-T

Substation name	Number of protection relays
Australian News Print 132 kV	3
Bayswater 500 kV	8
Bannaby 500/330 kV	4
Beaconsfield 330 kV	9
Boambee South 132 kV	2
Buronga 220 kV	5
Canberra 330 kV	8
Dapto 330 kV	2
Forbes 132 kV	16
Finley 132 kV	17
Gunnedah 132 kV	11
Inverell 132 kV	17
Jindera 330 kV	2
Kemps Creek 500 kV	20
Koolkhan 132 kV	11
Kempsey 132 kV	26
Lismore 330 kV	17
Macarthur 330 kV	9
Munmorah 330 kV	1
Manildra 132 kV	2
Munyang 132 kV	1
Mt Piper 132 kV	14
Moree 132 kV	3
Mt Piper 500 kV	11
Murray 330 kV	1
Macksville 132 kV	2
Nambucca 132 kV	16
Newcastle 330 kV	48
Orange North 132 kV	5

Parkes 132 kV	3
Pt Macquarie 132 kV	9
Queanbeyan 132 kV	11
Raleigh 132 kV	2
Sydney South 330 kV	15
Sydney West 330 kV	2
Tumut 1 Power Station	4
Tumut 2 Power Station	4
Tamworth 330 kV	1
Taree 132 kV	2
Tenterfield 132 kV	10
Upper Tumut 330 kV	3
Vineyard 330 kV	5
Williamsdale 330 kV	7
Wagga North 132 kV	8
Wellington 330 kV	21
Wollar 500 kV	1
Waratah West 330 kV	6
Wallerawang 132 kV	14