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Maintaining compliance with performance standards applicable to Cowra substation secondary systems

RIT-T Project Specification Consultation Report

Region: Central-West New South Wales

Date of issue: 24 January 2025

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options focused on maintaining the safe and reliable operation of Cowra substation. This Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T.

Cowra 132/66kV Substation comprises of 3x 132kV feeders, 2x 132/66kV transformers and 5x 66kV feeders. It is a customer connection point supplying the Essential Energy 66kV network in the area inclusive of Young, Canowindra and Grenfell.

Secondary systems assets at Cowra substation are facing technological obsolescence. This obsolescence increases both the time to rectify defects and the risk that primary assets at the substation may not be able to reliably operate.

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

Secondary systems are used to control, monitor, protect and provide communication to facilitate safe and reliable network operation.[1] They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur.

The secondary system assets at Cowra are subject to technological obsolescence. This means that the technology is no longer being manufactured or supported. Reactive replacement of failed secondary systems components is not sustainable and impacts our ability to meet the requirements of the National Electricity Rules (NER).

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 NER, therefore the condition issues affecting the identified protection relays on the 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 systems where a secondary systems 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 lines at a voltage above 66 kV are well-maintained so as to be available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out.[2] 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.[3]

Furthermore, as per clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

1 As per Schedule 5.1 of the NER.
2 As per S5.1.2.1(d) of the NER.
3 AEMO. "Power System Security Guidelines, 3 June 2024." Melbourne: AEMO, 2024. Accessed 4 June 2024.

A failure of the secondary systems would involve replacement of the failed component or removing the affected primary assets, such as lines and transformers, out of service. Though replacement of 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, 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 secondary systems 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.

Two credible network options have been identified

We have identified two credible network options that would meet the identified need from a technical, commercial, and project delivery perspective.[4] These options are summarised in Table E-1 below.

Table E-1 Summary of credible options

Option	Description	Estimated capex ($2024/25m, +/- 25%)	Operating costs ($2024/25, $ per year)
Option 1	Replace individual assets	11.78	16,573
Option 2	Complete in-situ renewal	11.41	4,562

Assets with deteriorating condition to be replaced include protection schemes, control systems and metering schemes. See Appendix B for a full list of assets to be replaced under Option 1 and Option 2.

Non-network options are not expected to be able to assist with 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 secondary systems, metering or control and ensure that the transmission system is adequately protected.

Draft Conclusion

This PSCR finds that implementation of Option 2 is the preferred option to address the identified need. Option 2 involves replacement of all secondary systems at the site. This option will adopt an automation philosophy consistent with current design standards and practices. This option also includes replacement

4 As per clause 5.15.2(a) of the NER.

of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415 V Alternating Current (AC) distribution in the building and switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, and DC supply systems creates a need for modernisation. This will deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. There are also additional operational benefits available to improved remote monitoring, control and interrogation, efficiency gains in responding to faults, and phasing out of obsolete and legacy systems and protocols.

The capital cost of this option is approximately $11.41 million (in $2024/25). The works will be undertaken between 2024/25 and 2026/27. Planning, design, development and procurement (including the completion of the RIT-T) will occur between 2024/25 and 2025/26, while project delivery and construction will occur in 2026/27. All works are expected to be completed by 2026/27, with final commissioning of the solution expected in 2027/28 to best meet the need of meeting the service level required for protection schemes. Routine operating and maintenance costs are estimated to be approximately $4,562 per annum (in $2024/25).

Exemption from preparing a Project Assessment Draft Report

Subject to the identification of additional credible options during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider that the conditions in clause 5.16.4(z1) of the NER exempting RIT-T proponents from providing a PADR have been met.

Specifically, production of a PADR is not required because:

- the estimated capital cost of the preferred option is less than $54 million[5];
- we have identified in this PSCR our proposed preferred option, together with the reasons for the preferred option; and
- the proposed preferred option and any other credible options in respect of the identified need do not have any material market benefits (except for market benefits arising from changes in involuntary load shedding).

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a Project Assessment Draft Report (PADR) that updates the NPV assessment presented in this PSCR.

Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 3 May 2025.[6]

[5] Varied from $43m to $54m based on the AER Final Determination: Cost threshold review, November 2024.
[6] Consultation period is for 12 weeks. Additional days have been added to cover public holidays.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[7] In the subject field, please reference 'Cowra Secondary Systems 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.

We intend to produce a Project Assessment Conclusions Report (PACR) that addresses all submissions received and presents our draft analysis and conclusion on the preferred option for this RIT-T. Subject to submissions to this PSCR, we anticipate publication of a PACR by the end of June 2025.

[7] 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.

Contents

1. Introduction

We are applying this Regulatory Investment Test for Transmission (RIT-T) to options focused on maintaining the safe and reliable operation of Cowra 132/66 kV Substation. This Project Specification Consultation Report (PSCR) represents the first step in the application of the 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 credible option that we currently consider addresses the identified need;
- explain the basis on which we have concluded that non-network options are not expected to be able to contribute to meeting the identified need for this RIT-T;
- summarise the assumptions proposed to feed into the PADR analysis; and
- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

Overall, this report provides transparency into planning considerations for investment options addressing the risk of secondary systems failure at Cowra substation. A key purpose of this PSCR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

1.2. Exemption from producing a Project Assessment Draft Report

Subject to the identification of additional credible options during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider that the conditions in clause 5.16.4(z1) of the NER exempting RIT-T proponents from providing a PADR have been met.

Specifically, production of a PADR is not required because:

- the estimated capital cost of the preferred option is less than $54 million[9];
- we have identified in this PSCR our proposed preferred option, together with the reasons for the preferred option; and
- the proposed preferred option and any other credible options in respect of the identified need do not have any material market benefits (with the exception of market benefits arising from changes in involuntary load shedding).

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a Project Assessment Draft Report (PADR) that updates the NPV assessment presented in this PSCR.

1.3. Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 3 May 2025.[10]

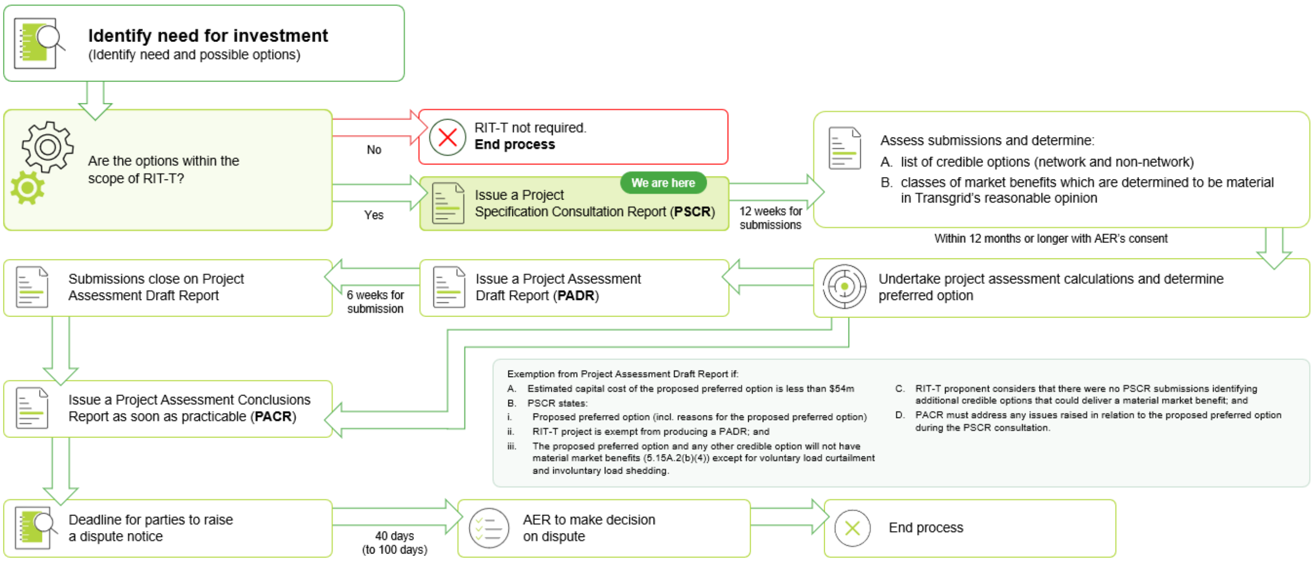
8 See Appendix A for the NER requirements.
9 Varied from $43m to $54m based on the AER Final Determination: Cost threshold review, November 2024.
10 Consultation period is for 12 weeks. Additional days have been added to cover publish holidays.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[11] In the subject field, please reference ‘Cowra Secondary Systems 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.

Should we consider that no additional credible options were identified during the consultation period, we intend to produce a Project Assessment Conclusions Report (PACR) that addresses all submissions received including any issues in relation to the proposed preferred option raised during the consultation period. Subject to additional credible options being identified, we anticipate publication of a PACR by the end of June 2025.

Figure 1-1 This PSCR is the first stage of the RIT-T process[12]



[11] 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.

[12] Australian Energy Market Commission. “*Replacement expenditure planning arrangements, Rule determination*”. Sydney: AEMC, 18 July 2017.

2. The identified need

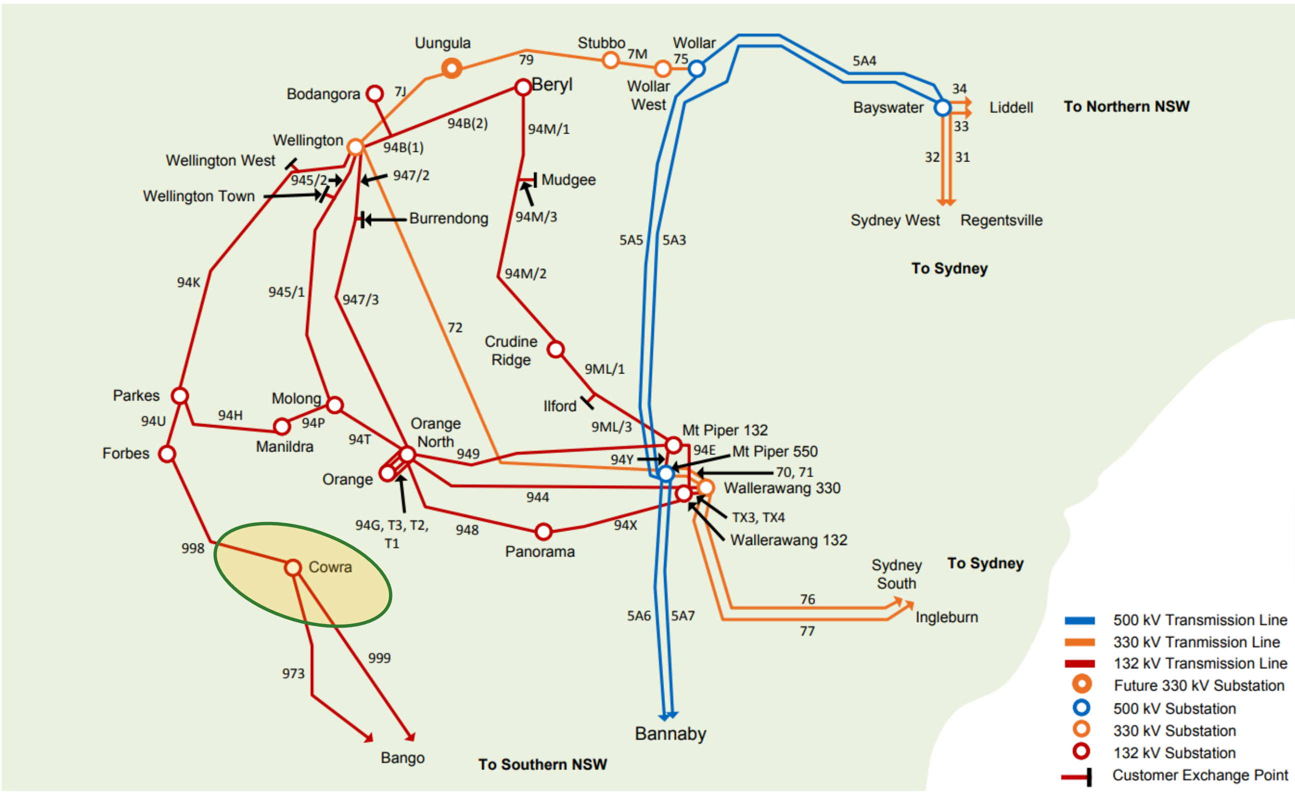
2.1. Background to the identified need

We are applying this Regulatory Investment Test for Transmission (RIT-T) to options focused on maintaining the safe and reliable operation of Cowra substation. This Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T.

Cowra 132/66kV Substation comprises of 3x 132kV feeders, 2x 132/66kV transformers and 5x 66kV feeders. It is a customer connection point supplying the Essential Energy 66kV network in the area inclusive of Young, Canowindra and Grenfell.

Figure 2-1 provides a simplified schematic diagram of the Central West Transmission Network and shows the location of the Cowra 132/66kV substation within this network.

Figure 2-1 Location of Cowra substation within the Central-West Transmission Network



2.2. Description of the identified need

Secondary systems are used to control, monitor, protect and provide communication to facilitate safe and reliable network operation.[13] They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur.

[13] As per Schedule 5.1 of the NER.

The secondary system assets at Cowra are subject to technological obsolescence. This means that the technology is no longer being manufactured or supported. Reactive replacement of failed secondary systems components is not sustainable and impacts our ability to meet the requirements of the National Electricity Rules (NER).

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 NER, therefore the condition issues affecting the identified protection relays on the 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 systems where a secondary systems 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 lines at a voltage above 66kV are well-maintained so as to be 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]

Furthermore, as per clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

A failure of the secondary systems would involve replacement of the failed component or removing the affected primary assets, such as lines and transformers, out of service. Though replacement of 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, 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 secondary systems 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.

14 As per S5.1.2.1(d) of the NER.
15 AEMO. "Power System Security Guidelines, 3 June 2024 (DRAFT)." Melbourne: AEMO, 2024. Accessed 4 June 2024.

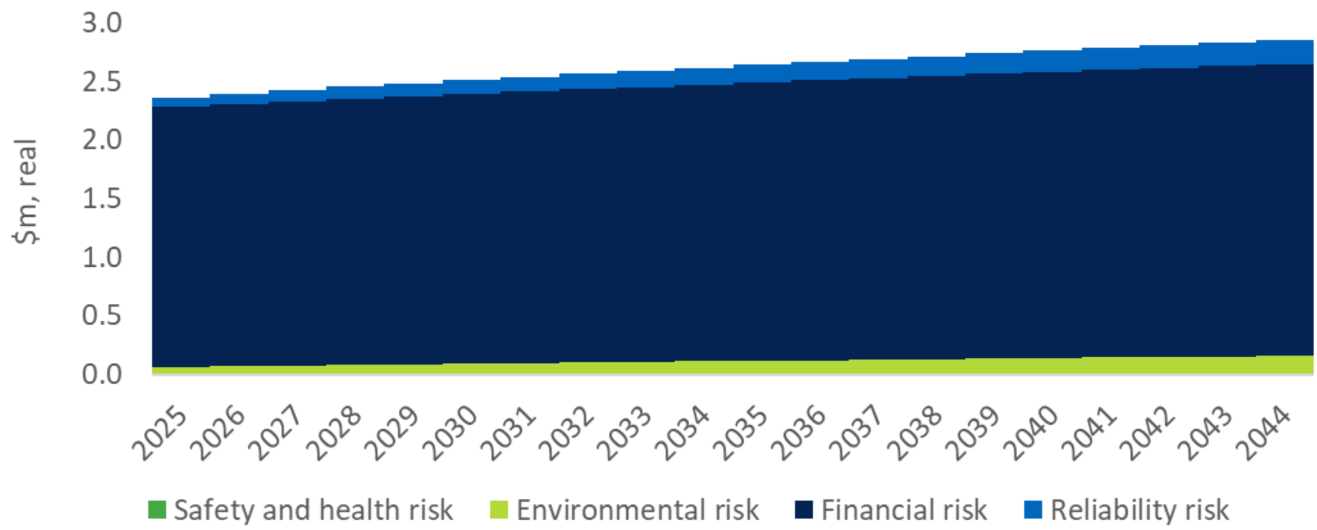
2.3. Assumptions underpinning the identified need

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

We note that the risk cost estimating methodology aligns with that used in our 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 2-2 summarises the increasing risk costs over the assessment period under the base case.

Figure 2-2 Estimated risk costs under the base case (central scenario, $m, 2024/25)



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. For the central scenario, the aggregate risk cost under the base case is currently estimated at around $2.36 million/year. Risk costs are expected to increase going forward if action is not taken and the secondary systems assets are left to deteriorate further (reaching approximately $2.74 million/year by the end of the 15-year assessment period).

2.3.1. Asset health and the probability of failure

2.3.1.1. Protection relays

Protection relays are assets that monitor the network and trip circuit breakers when an abnormality in the network is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the NER.[16]

24 protection relays at Cowra substation are being targeted for replacement. A list of these relays can be found in Appendix B. The effective age of these relays in 2027/28 ranges from 12 years to 54 years, with an average effective age of 20 years. In contrast, the typically useful life of a relay is around 15 years. Key issues presented by these relays are:

[16] S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times

- exceedance of their technical life and/or relay type experiencing increased failure rates; and
- technology obsolescence resulting in a lack of spares and no manufacturer support.
- younger relays have also faced ongoing issues with no resolution from the manufacturer.

71% of the protection relays in 2027/28 included in this RIT-T are at or beyond the end of their technical life, with some of the remaining targeted assets facing ongoing performance issues. If left unreplaced, it is likely that a number of these assets will fail at an increasing rate going forward. This may result in involuntary load shedding on parts of the network and increased costs to replace these assets in a reactive fashion. Like-for-like replacements in the event of failures are not feasible due to the absence of technical support from the manufacturers. This will mean that replacing the currently installed protection relays after a failure will take considerably longer and result in significant corrective maintenance costs as new relays will be required rather than just relay components. Replacement of the protection relays is required to ensure compliance with the NER, including requirements around maintaining adequate protection systems[17] and maximum clearance times.[18]

2.3.1.2. Control systems

Control assets allow for the remote monitoring, control and automation of primary assets. These assets allow us to operate and monitor the status of unmanned substations and switching stations throughout the state. These assets also collect significant amounts of status and condition information to facilitate some level of remote diagnostics during failures and faults.

We have identified all control system assets at Cowra substation experiencing increasing failure rates and a lack of spares and manufacturer support which are targeted for replacement. A list of these control systems can be found in Appendix B. The effective age in 2027/28 of these control system is 21 years. In contrast, the typically useful life of control systems are around 15 years. Key issues presented by control systems are:

- exceedance of their technical life and model types experiencing increased failure rates; and
- technology obsolescence resulting in a lack of spares and no manufacturer support.
- Control system is limited in capacity due to age of technology.

These control systems have reached the end of their technical life, increasing the risk that they will not operate properly when required. A failure of control systems will significantly undermine our ability to operate the substation remotely, and to detect failures in other substation assets when they occur. Replacement of these control systems is required to ensure compliance with the NER, including requirements to ensure that remote monitoring and control systems are maintained in accordance with the standards and protocols determined and advised by AEMO.[19]

2.3.1.3. Metering Schemes

Metering assets are an NER compliance requirement to facilitate the settlement of the market. These assets are critical the accurate billing of the electricity market.

6 meters at Cowra substation are being targeted for replacement. A list of these meters can be found in Appendix B. The effective age of these meters in 2027/28 ranges from 13 years to 15 years, with an

[17] NER, s5.1.2.1(d) and s5.1.9(c).
[18] NER, s5.1a.8.
[19] NER, clause 4.11.1.

average effective age of 14 years. In contrast, the typically useful life of a meter is around 15 years. Key issues presented by these relays are:

- exceedance of their technical life; and
- upcoming technology obsolescence resulting in a lack of spares and no manufacturer support.

33% of the meters in 2027/28 included in this RIT-T are at or beyond the end of their technical life, with some of the remaining targeted assets reaching end of life in 2028/29. If not renewed to latest standards, this may result in future loss of accuracy and increased costs to replace these assets in a reactive fashion.

2.3.2. Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence considers duplicated protection or control system. In addition, the financial consequence of primary plant considers the likelihood of a fault occurring during the failure of both protection schemes and the likelihood of the watchdog failing to successfully detect the failed unit where available. The monetary value considers the cost of replacement or repair of the failed asset and the protected asset, including any temporary measures across protection and control systems. Due to the obsolescence of many of the assets targeted in this need, their failure will result in a complete redesign and renewal under defect conditions as direct replacement is no longer feasible.

Financial risk makes up 90 per cent of the total estimated risk cost.

2.3.3. Reliability risk

The risk of unserved energy for customers following a failure of secondary systems identified has been assessed in the NPV analysis. The likelihood of a consequence considers the likelihood of duplicated secondary systems failing, the likelihood of a fault occurring during the failure of both secondary systems, 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.

For protection assets 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 500kV and 330kV 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 500kV and 330kV 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.

Control systems risks have factored the loss of monitoring and control of primary assets which will result in extended outages in the event of a credible contingency occurring. This risk forms a part of the reliability risk calculated and is evaluated based on the unserved energy consequence of individual primary plant and likelihood of a fault occurring during the outage of the control system.

We have considered the risk of unserved energy for customers following a failure of one or more of the secondary systems assets identified in this PSCR.

Reliability risk makes up 6 per cent of the total estimated risk cost.

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.

Environmental risk makes up 4 per cent of the total estimated risk cost.

2.3.5. 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.

Safety risk makes up less than one per cent of the total estimated risk cost.

3. Potential credible options

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.[20] This will include any credible options that are put forward by proponents in response to this PSCR.

Table 3-1 summarises each of the credible options we currently consider can meet the identified need. Neither credible option is expected to have a material inter-regional impact

Table 3-1: Summary of the credible options

Option	Description	Estimated capex ($2024/25m, +/- 25%)	Operating costs ($2024/25, $ per year)
Option 1	Replace individual assets	11.78	16,573
Option 2	Complete in-situ renewal	11.41	4,562

3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PSCR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken, ie:[21]

> "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 proactive capital investment is made to remediate the deterioration of the secondary systems at Cowra substation, address the technological obsolescence, spares unavailability, and discontinued manufacturer support for these assets. The assets will continue to be operated and maintained under the current regime.

The routine operating and maintenance costs under the base case are estimated at approximately $16,573 in FY25, temporarily increasing to $99,735 in FY28 before decreasing back to $16,573 in FY32 for the rest of the 15-year assessment period (in $2024/25). The substantial increase in opex during FY28 to FY31 is due to building refurbishment works, which were necessary to address the rectification costs identified in the dilapidation reports.

Table 3-2 Breakdown of capital and operating expenditure under the base case

Year	Capital cost ($m, 2024/25)	Operating costs ($2024/25, $ per year)
2025	-	16,573
2026	-	16,573
2027	-	16,573

[20] As per clause 5.15.2(a) of the NER.
[21] AER, *Regulatory Investment Test for Transmission Application Guidelines,* November 2024, p.21.

2028	-	99,735
2029	-	99,735
2030	-	99,735
2031	-	99,735
2032	-	16,573
2033	-	16,573
2034	-	16,573
2035	-	16,573
2036	-	16,573
2037	-	16,573
2038	-	16,573
2039	-	16,573

While this is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the assessment is required to use this base case as a common point of reference when estimating the net benefits of each credible option.

3.2. Option 1 – Replacement of individual assets

Option 1 is centred on a like-for-like replacement of identified assets by a modern equivalent. Additional system modifications or additional functionalities would not be deployed under this option. This option will lock Transgrid to a system architecture that cannot be expanded to match modern technology capabilities into the future.

This option would deliver the least benefits to consumers and the network by only affecting the probability of failure of targeted assets. This option will not provide any additional operational benefits such as improved capabilities for remote interrogation and predictive activities.

This option is planned for deployment across the 2023/24-2027/28 regulatory period with remaining assets at the site to incur investment in future years. Targeted assets will be in service for approximately 15 years. The assets that will be replaced under this option are set out in Appendix B.

The capital cost of this option is approximately $11.78 million (in $2024/25). The work will be undertaken in stages over the 15-year assessment period. This capital cost is comprised of $4.88m in labour costs, $4.92m in material costs, and $1.98m in expenses.

The routine operating and maintenance costs under the base case are estimated at approximately $16,573 in FY25, temporarily increasing to $99,735 in FY28 before decreasing back to $16,573 in FY32 for the rest of the 15-year assessment period (in $2024/25). As mentioned previously, the increase in opex during FY28 to FY31 is due to building refurbishment works, which were necessary to address the rectification costs identified in the dilapidation reports, which is also relevant in this option. We expect that the new protection relays and control systems, will have an asset life of 15 years.

Table 3-3 Capital and operating cost of Option 1

Year	Capital cost ($m, 2024/25)	Operating costs ($2024/25, $ per year)
2025	0.81	16,573
2026	0.81	16,573
2027	0.81	16,573
2028	0.81	99,735
2029	7.80	99,735
2030	-	99,735
2031	0.08	99,735
2032	-	16,573
2033	0.25	16,573
2034	0.08	16,573
2035	0.08	16,573
2036	-	16,573
2037	0.23	16,573
2038	-	16,573
2039	-	16,573

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 impact on the network.

3.3. Option 2 – Complete in-situ replacement

This option involves replacement of all secondary systems assets at the site. This option will adopt an automation philosophy consistent with current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, and DC supply systems creates a need for modernisation.

The work will be undertaken in stages over a three-year period with all works expected to be completed by 2026/27.

The capital cost of this option is approximately $11.41 million (in $2024/25). This cost is comprised of $2.96m labour, $4.31m in material costs and $4.13m in expenses.

The routine operating and maintenance costs are estimated at approximately $16,573 in FY25, decreasing to $4,562 in FY27 continuing until the end of the 15-year assessment period (in $2024/25).

Table 3-4 Capital and operating cost of Option 2

Year	Capital cost ($m, 2024/25)	Operating costs ($2024/25, $ per year)
2025	2.19	16,573
2026	7.30	16,573
2027	1.92	4,562
2028	-	4,562
2029	-	4,562
2030	-	4,562
2031	-	4,562
2032	-	4,562
2033	-	4,562
2034	-	4,562
2035	-	4,562
2036	-	4,562
2037	-	4,562
2038	-	4,562
2039	-	4,562

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 impact on the network.

3.4. Options considered but not progressed

We considered other options that were not progressed as they were considered not technically or economically feasible. These options are outlined in the table below.

Table 3-5: Options considered but not progressed

Option	Reason(s) for not progressing
Complete Secondary Systems Buildings (SSB) Replacement	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement.
Upgrade to IEC61850	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement.
Asset Retirement	This can only be achieved by retiring the associated primary assets, which is not technically or economically feasible. This site will remain an essential connection point into the foreseeable future.

Option	Reason(s) for not progressing
Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection, control, communications and metering.

3.5. No material inter-network impact is expected

We have considered whether the option outlined above is expected to have material inter-regional impact.[22] 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:[23]

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

We note that the credible option identified 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 the credible option considered.

3.6 Community engagement

Social licence costs can be reduced through early and continued engagement with communities and stakeholders who are reasonably expected to be affected by the project.

Transgrid is not proposing to undertake specific community engagement (in addition to the publication of the RIT-T consultation reports) in relation to this project. The proposed project relates to replacement of infrastructure within an existing substation and as such there will beno additional impact on communities apart from construction activities who are located close to the current transmission infrastructure. Transgrid will ensure that all construction works associated to the project are conducted in a manner that causes the least disruption to communities and notes that the construction activities will be subject to separate environmental approval.

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

[23] 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

As a result, Transgrid does not consider that there is a need for additional community engagement as part of this RIT-T process. We will still engage with community as part of our project's construction works notifications and welcome any submissions from community members to this PSCR.

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 or 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. This consideration also extends to the ability to meet regulatory obligations under clauses 4.6.1 and 4.11.1 related to remote monitoring and control systems.

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.[24]

5.1. Avoided unserved energy has been estimated

We have estimated the expected unserved energy if action is not taken to address the identified need.

In the base case, load shedding would be expected to occur if there is a single or multiple outage of 132/66/11kV transformers, and this contingency event occurs at or near times of high demand. Under these circumstances, load shedding will be required to maintain transformer load below the firm capacity of the remaining in-service transformers.

We have estimated expected load shedding under the base case and under each of the credible options. These forecasts were based on probabilistic planning studies of transformer failure rates and repair times. Each of the credible options significantly reduce the amount of expected load shedding that would occur. The avoided unserved energy for each credible option is calculated as the difference between the expected load shedding under the base case and the expected load shedding under the credible option.

Other categories of market benefits prescribed in the NER have not been estimated and are not considered material for this RIT-T.

5.2. 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.[25]

The credible option considered in this RIT-T will not address network constraints between competing generating centres and is 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 RIT-T 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; and
- competition benefits.

5.3. No other classes of market benefits are considered material

In addition to the classes of market benefits discussed above, NER clause 5.15A.2(b)(4) requires that we consider the following classes of market benefits arising from each credible option. We consider that none

[24] As per NER clause 5.15A.2(b)(4) See Appendix A for requirements applicable to this document.
[25] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, November 2024, Melbourne: Australian Energy Regulator.

of the classes of market benefits listed below will be material for this RIT-T assessment for the reasons in Table 5-1.

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

Market benefits	Reason
Difference in the timing of unrelated expenditure	The investment will not affect investment in other parts of the network.
Option value	We note the AER's view is 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.[26] Neither option is flexible enough to respond to changes or uncertainty for this RIT-T.
Changes in Australian greenhouse gas emissions	Neither option in this RIT-T is expected to affect the dispatch of generation in the wholesale market. No other material source of a change in Australian emissions has been identified.

[26] AER, *Regulatory Investment Test for Transmission – Application Guidelines*, November 2024, p. 56-57.

6. Overview of the assessment approach

This section outlines the approach that we are proposing to apply in assessing the net benefits associated with the credible options.

6.1. Assessment period and discount rate

A 15-year assessment period from 2024/25 to 2038/39 has been adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of each option.

Where the capital components have asset lives extending beyond the end of the assessment period, the NPV modelling includes a residual value to capture the remaining functional asset life. This ensures that the capital cost of the long-lived assets over the assessment period is appropriately captured, and that costs and benefits are assessed over a consistent period, irrespective of option type, technology or serviceable 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 7.00 per cent has been adopted as the central assumption for the NPV analysis, consistent with AEMO's latest Input Assumptions and Scenarios Report (IASR).[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 results to a lower bound discount rate of 3.63 per cent.[28] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest IASR).[29]

6.2. Approach to estimating option costs

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

All costs estimated by Transgrid's project development team use the estimating tool 'MTWO'. The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- period order agreement rates and market pricing for plant and materials;
- labour quantities from recently completed project; and
- construction tender and contract rates from recent projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs[30]). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.[31]

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27 AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.
28 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis, see: https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29/final-decision.
29 AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.
30 I.e., there is an equal likelihood of over- or under-spending the estimate total.
31 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.

Transgrid does not generally apply the Association for the Advancement of Cost Engineering (AACE) international cost estimate classification system to classify cost estimates. Doing so for this RIT-T would involve significant additional costs, which would not provide a corresponding increase in benefits compared with the use of MWTO estimates and so this has not been undertaken.

We estimate that actual costs will be within +/- 25 per cent of the central capital cost estimate. While we have not explicitly applied the AACE cost estimate classification system, we note that 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 AACE classification system.

No specific contingency allowance has been included in the cost estimates.

Work is planned along existing Transgrid easements, where access is expected to be available. Only minor access track upgrades have been assessed as part of the desktop assessment. Where civil works is anticipated, normal soil conditions have been assumed.

All cost estimates are prepared in real 2024/25 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.

On 21 November 2024, the requirements set out in the Australian Energy Regulator's Regulatory Investment Test for Transmission (RIT-T) Application Guidelines were amended. The amended guidelines now expect a RIT-T proponent to explicitly consider community engagement and social licence during the RIT-T process.

The amended guidelines mean that Transgrid must consider social licence principles in the identification of credible options. This may affect how we determine the most likely cost and delivery timeline for an option.

Transgrid believes building relationships and trust is how we can gain and grow social licence. Through engagement with affected communities we identify prudent and efficient investment opportunities that can build and gain community acceptance for our options. Costs associated with social licence include those associated with engagements, community benefits, minor route adjustments and legislated additional landholders payments, as applicable.

We acknowledge this important change to the RIT-T guidelines. However, due to nature of these works being replacement of infrastructure within an existing substation, and therefore low impact on community, we do not anticipate the need to provide additional costs to address social licence considerations (as outlined in section 3.6).

6.3. The option has been 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 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.

The credible options have been assessed under three scenarios as part of this PSCR assessment, which differ in terms of the key drivers of the estimated net market benefits.

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios implicitly assume the most likely scenario from the 2023 IASR (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, 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 (such as the discount rate and capital costs) has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type.[32]

A summary of the key variables in each scenario is provided in the table below.

Table 6-1 Summary of scenarios

Variable / Scenario	Central scenario	Low risk costs scenario	High risk costs scenario
Scenario weighting	1/3	1/3	1/3
Discount rate	7%	7%	7%
VCR ($2024/25)[33]	$52,524/MWh	$52,524/MWh	$52,524/MWh
Network capital costs	Base estimate	Base estimate	Base estimate
Avoided unserved energy	Base estimate	Base estimate - 25%	Base estimate + 25%
Safety, environmental and financial risk benefit	Base estimate	Base estimate - 25%	Base estimate + 25%
Avoided routine operating and maintenance costs	Base estimate	Base estimate	Base estimate

6.4. Sensitivity analysis

We have also considered the robustness of the outcome of this RIT-T's cost benefit analysis through undertaking various sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PSCR are:

- lower and higher assumed VCRs;
- lower and higher capital costs of the credible options;
- lower and higher risk costs of the credible options; and

32 AER, *Application Guidelines Regulatory Investment Test for Transmission*, November 2024, p.42-44

33 This VCR is sourced from AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124. However, this VCR has been escalated to June 2025 using historical Australian CPI and the RBA's 2024/25 CPI forecast

- alternate commercial discount rate assumptions.

In addition to the sensitivity tests listed above, we have also considered the sensitivity around the timing of when options are commissioned.

7. Assessment of the credible option

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of the option to the base case.

7.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The results have been presented separately for each reasonable scenario, and on a weighted basis.

The benefits included in this assessment are:

- avoided involuntary load shedding;
- reduction in safety, environmental and financial risks; and
- avoided routine operating and maintenance costs.

Table 7-1 : PV of gross economic benefits relative to the base case ($m, 2024/25)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	1/3	1/3	1/3	
Option 1	7.39	5.54	9.24	7.39
Option 2	17.01	12.76	21.27	17.01

The results show that under all three scenarios, the estimated gross benefits are positive for Options 1 and 2 in present value terms.

7.2. Estimated cost

The table below summarises the present value of the costs for Options 1 and 2 relative to the base case.

Table 7-2 PV of costs of credible options relative to the base case ($m, 2024/25)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	1/3	1/3	1/3	
Option 1	7.87	7.87	7.87	7.87
Option 2	9.77	9.77	9.77	9.77

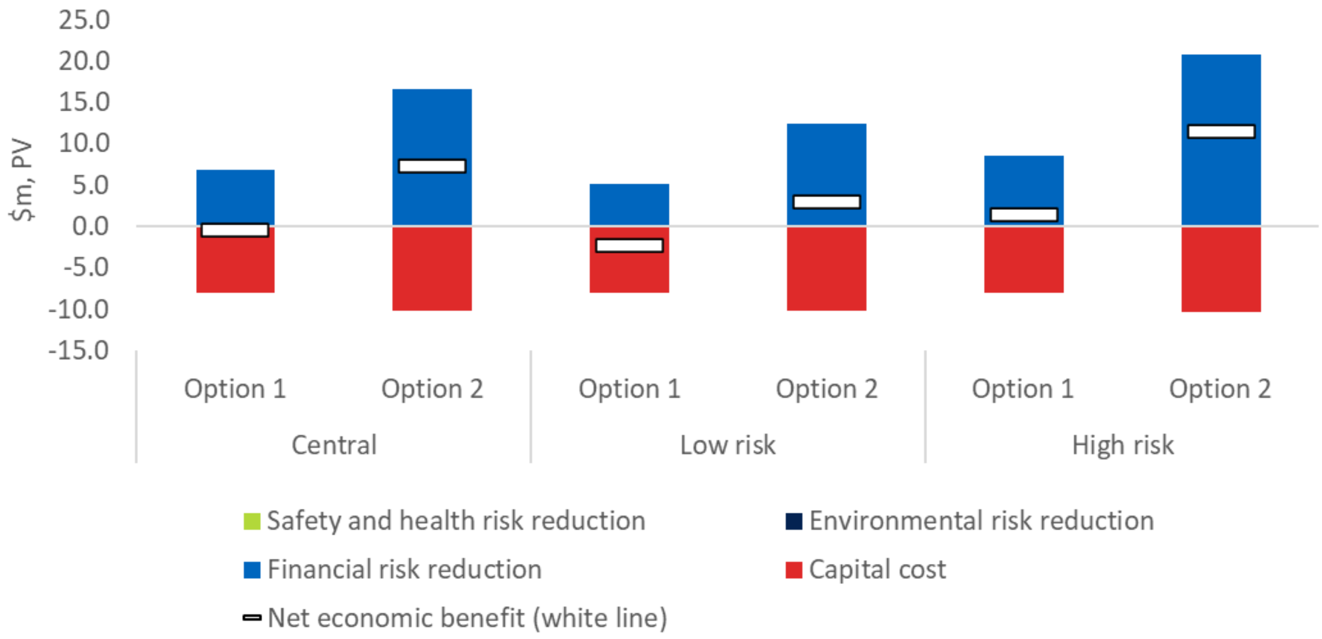
7.3. Estimated net economic benefits

The net economic benefits are calculated as the estimated gross benefits less the estimated costs plus the terminal value. The table below summarises the present value of the net economic benefits for each credible option. The results have been presented separately for each reasonable scenario, and on a weighted basis. Option 2 has the greatest net market benefits and is therefore our preferred option.

Table 7-3: PV of net economic benefits relative to the base case ($2024/25 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	1/3	1/3	1/3	
Option 1	-0.49	-2.33	1.36	-0.49
Option 2	7.25	2.99	11.50	7.25

Figure 7-1 PV of net economic benefits ($2024/25 m)



7.4. Sensitivity testing

We have undertaken sensitivity testing to understand the robustness of the RIT-T assessment to underlying assumptions about key variables. In particular, we have undertaken two sets of sensitivity tests:

- Step 1 – testing the sensitivity of the optimal timing of the project ('trigger year') to different assumptions in relation to key variables; and
- Step 2 – once a trigger year has been determined, testing the sensitivity of the total NPV benefit associated with the investment proceeding in that year, in the event that actual circumstances turn out to be different.

Having assumed to have committed to the project by this date, we have also looked at the consequences of 'getting it wrong' under step 2 of the sensitivity testing. That is, if expected safety and environmental risks are not as high as expected, for example, the impact on the net economic benefit associated with the project continuing to go ahead on that date.

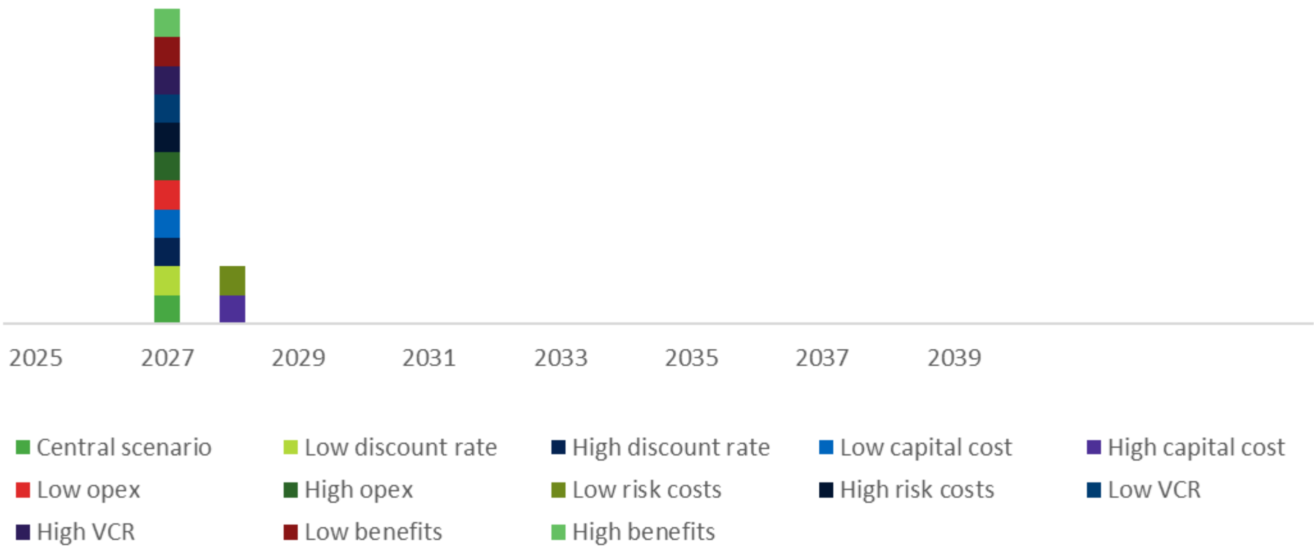
The application of the two steps to test the sensitivity of the key findings is outlined below.

7.4.1. Step 1 – Optimal timing

This section outlines the sensitivity of the identification of the commissioning year of Option 2 to changes in the underlying assumptions. In particular, the optimal timing of Option 2 is found to be largely invariant to most of the sensitivities undertaken on the central scenario (apart from a 25 per cent decrease in risk costs and a 25 per cent increase in capital cost).

Figure 7-2 below outlines the impact on the optimal commissioning year, under a range of alternative assumptions. It illustrates that for Option 2, the optimal commissioning date is overwhelmingly found to be in 2026/27.

Figure 7-2 Distribution of optimal timing under a range of different key assumptions



7.4.2. Step 2 – Overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit. Specifically, we have investigated the same sensitivities under this step as in the first step:

- a 25 per cent increase/decrease in the assumed network capital costs;
- a 25 per cent increase/decrease in the assumed safety, environmental and financial risks; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.5 per cent;

These sensitivities investigate the consequences of 'getting it wrong' having committed to a certain investment decision.

Figure 7-3, Figure 7-4, and Figure 7-5 below illustrate the impact on the estimated net economic benefit for each option if these key assumptions a varied individually in the central scenario. As can be seen, Option 2 is preferred to Option 1 across all these sensitivity tests.

Figure 7-3 Sensitivity of net economic benefits under a lower and higher risk costs ($2024/25 m)

Figure 7-4: Sensitivity of net economic benefits under lower and higher capital costs ($2024/25 m)

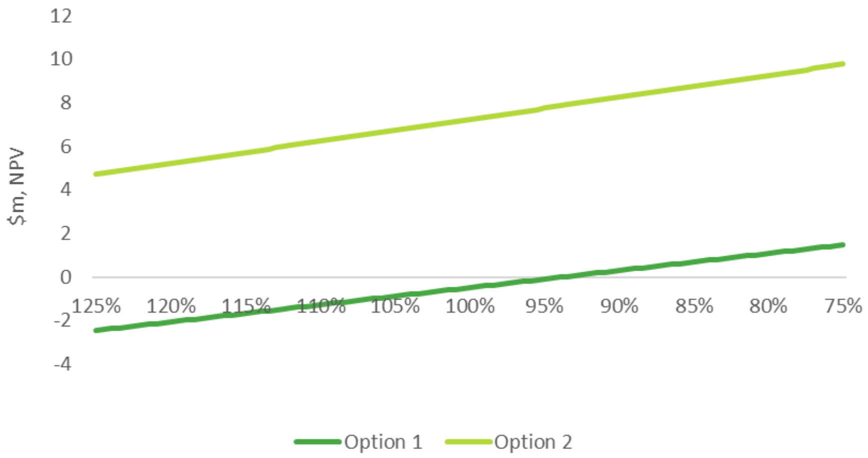
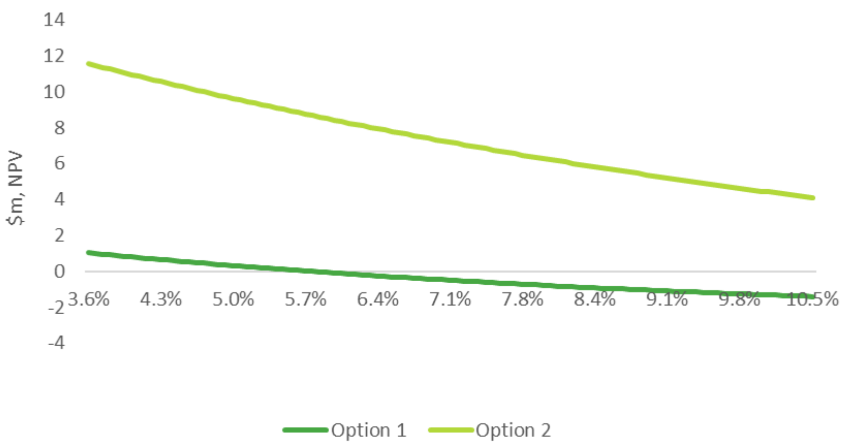


Figure 7-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2024/25 m)



Results from the sensitivity testing suggest that there are no reasonable changes to the discount rate, assumed network capital costs, or estimated risk costs that can alter the identification of the preferred option (Option 2). Regarding boundary testing, we find that the following would need to occur for Option 1 to have a net market benefit equal to that of Option 2:

- assumed network capital costs (for all options) would need to increase by 346 per cent;
- the estimated risk costs (in aggregate) would need to fall by 80 per cent; and
- the discount rate would need to be greater than 26.80 per cent.

We therefore consider that the preference of Option 2 over Option 1 is robust to changes in key underlying assumptions.

8. Draft conclusion and exemption from producing a PADR

This PSCR has found that Option 2 is the preferred option for this RIT-T. Option 2 involves the replacement of all secondary systems assets at Cowra 132/66kV substation. The estimated capital expenditure associated with Option 2 is $11.41 million (in 2024/25 dollars).

The works will be undertaken between 2024/25 and 2026/27. Planning, design, development and procurement (including the completion of the RIT-T) will occur between 2024/25 and 2025/26, while project delivery and construction will occur in 2026/27. All works are expected to be completed by 2026/27, with final commissioning of the solution expected in 2027/28 to best meet the need of meeting the service level required for protection schemes. Routine operating and maintenance costs are estimated to be approximately $4,562 per annum (in $2024/25).

Option 2 is the preferred option in accordance with NER clause 5.15A.2(b)(12) because it is the credible option that maximises the net present value of the net economic benefit to all those who produce, consume and transport electricity in the market. The analysis undertaken and the identification of Option 2 as the preferred option satisfies the RIT-T.

Transgrid considers this conclusion to be robust to changes in capital costs and discount rates as there would need to be unrealistic changes to these key assumptions for the option preference to change (as shown via the sensitivity and boundary testing at the end of section 7.4). Transgrid will however continue to monitor these key assumptions and will notify the AER if such changes do occur (or appear likely), which would constitute a material change in circumstance.

Subject to additional credible options being identified during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider its investment in relation to the preferred option to be exempt from that part of the process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the proposed preferred option being less than $54 million[34];
- the PSCR states:
  - the proposed preferred option, together with the reasons for the proposed preferred option;
  - the RIT-T is exempt from producing a PADR; and
  - the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding except for voluntary load curtailment and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

We consider the investment in relation to all credible options identified meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

[34] Varied from $43m to $54m based on the AER Final Determination: Cost threshold review, November 2024.

Should we consider that no additional credible options were identified during the consultation period, we intend to produce a PACR that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 223.

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
	(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 National Transmission Network Development 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, 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(c)(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

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[35] (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 5.16.1(c)(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 5.16.1(c)(4) except those classes specified in clauses 5.16.1(c)(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

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Section in the PSCR
3.5A.1	Where the estimated capital costs of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T for all credible options (including the preferred option), either • apply the cost estimate classification system published by the AACE, or • if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate	NA

[35] Varied to $54m based on the AER Final Determination: Cost threshold review, November 2024.

3.5A.2	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: all key inputs and assumptions adopted in deriving the cost estimate a breakdown of the main components of the cost estimate the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	6.2
3.5.3	The RIT-T proponent is required to provide the basis for any social licence costs in their RIT-T reports, and may choose to refer to best practice from a reputable, independent and verifiable source.	6.2
3.8.2	Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	NA
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined.	NA
4.1	RIT-T proponents are required to describe in each RIT-T report • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement	3.6

Appendix B Assets identified for replacement

Table B-1 presents a list of the specific assets with deteriorating condition to be replaced under Option 2.

Table B-1 List of assets to be replaced under Option 2

Item	Asset
Protection Relays	132kV Bus – No1 Protection 132kV Bus – No2 Protection 66kV Bus – No1 Protection 66kV Bus – No2 Protection Line 999 132kV – No1 Protection Line 999 132kV – No2 Protection Line 973 132kV – No1 Protection Line 973 132kV – No2 Protection Line 998 132kV – No1 Protection Line 998 132kV – No2 Protection Line 891 66kV – No1 Protection Line 891 66kV – No2 Protection Line 866 66kV – No1 Protection Line 866 66kV – No2 Protection Line 863 66kV – No1 Protection Line 863 66kV – No2 Protection Line 865 66kV – No1 Protection Line 865 66kV – No2 Protection Line 893/1 66kV – No1 Protection Line 893/1 66kV – No2 Protection Transformer 1 132kV – No1 Protection Transformer 1 132kV – No2 Protection Transformer 3 132kV – No1 Protection Transformer 3 132kV – No2 Protection Capacitor 1 66kV – No1 Protection Capacitor 1 66kV – No2 Protection Capacitor 2 66kV – No1 Protection Capacitor 2 66kV – No2 Protection
Control Systems	Sitewide Bay Controller Site SCADA Gateway 110V DC Supply A 110V DC Supply B
Metering Systems	Transformer 1 132kV – Revenue Metering Transformer 3 132kV – Revenue Metering Line 891 66kV – Check Metering Summated Line 66kV – Check Metering

Table B-2 presents a list of Protection Schemes considered under this RIT-T. We have identified the following Protection Schemes at Cowra substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-2 Protection schemes examined within this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
132kV Bus – No1 Protection	53	Exceeded technical life and/or relay type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
132kV Bus – No2 Protection	53	
66kV Bus – No1 Protection	53	
66kV Bus – No2 Protection	53	
Line 999 132kV – No1 Protection	18	
Line 999 132kV – No2 Protection	15	
Line 973 132kV – No1 Protection	18	
Line 973 132kV – No2 Protection	15	
Line 998 132kV – No1 Protection	18	
Line 998 132kV – No2 Protection	15	
Line 891 66kV – No1 Protection	17	
Line 891 66kV – No2 Protection	14	
Line 866 66kV – No1 Protection	15	
Line 866 66kV – No2 Protection	14	
Line 863 66kV – No1 Protection	17	
Line 863 66kV – No2 Protection	15	
Line 865 66kV – No1 Protection	17	
Line 865 66kV – No2 Protection	14	
Line 893/1 66kV – No1 Protection	17	
Line 893/1 66kV – No2 Protection	14	
Transformer 1 132kV – No1 Protection	15	
Transformer 1 132kV – No2 Protection	15	
Transformer 3 132kV – No1 Protection	16	
Transformer 3 132kV – No2 Protection	16	
Capacitor 1 66kV – No1 Protection	14	
Capacitor 1 66kV – No2 Protection	13	
Capacitor 2 66kV – No1 Protection	14	
Capacitor 2 66kV – No2 Protection	13	

Table B-3 presents a list of Control Systems considered under this RIT-T. We have identified the following Control Systems at Cowra substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-3 Control Systems considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
Sitewide Bay Controller	22	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
SCADA Gateway	19	
110V DC Supply – No1 Battery	16	
110V DC Supply – No2 Battery	15	
110V DC Supply – No1 Charger	18	
110V DC Supply – No2 Charger	21	

Table B-3 presents a list of Metering systems considered under this RIT-T. We have identified the following Metering Systems at Cowra substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-4 Metering systems considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
Transformer 1 132kV – Revenue Metering	14	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
Transformer 3 132kV – Revenue Metering	14	
Line 891 66kV – Check Metering	15	
Summated Line 66kV – Check Metering	15	

Table B-5 presents a list of assets to be replaced under Option 1.

Table B-5 Assets to be replaced under Option 1

Item	Asset
Protection Relays	Line 999 132kV – No1 Protection Line 999 132kV – No2 Protection Line 973 132kV – No1 Protection Line 973 132kV – No2 Protection Line 998 132kV – No1 Protection

	Line 998 132kV – No2 Protection Line 891 66kV – No1 Protection Line 891 66kV – No2 Protection Line 866 66kV – No1 Protection Line 866 66kV – No2 Protection Line 863 66kV – No1 Protection Line 863 66kV – No2 Protection Line 865 66kV – No1 Protection Line 865 66kV – No2 Protection Line 893/1 66kV – No1 Protection Line 893/1 66kV – No2 Protection Transformer 1 132kV – No1 Protection Transformer 1 132kV – No2 Protection Transformer 3 132kV – No1 Protection Transformer 3 132kV – No2 Protection Capacitor 1 66kV – No1 Protection Capacitor 2 66kV – No1 Protection
Control Systems	Site SCADA Gateway 110V DC Supply A – Battery Only 110V DC Supply B – Battery Only
Metering Systems	Transformer 1 132kV – Revenue Metering Transformer 3 132kV – Revenue Metering

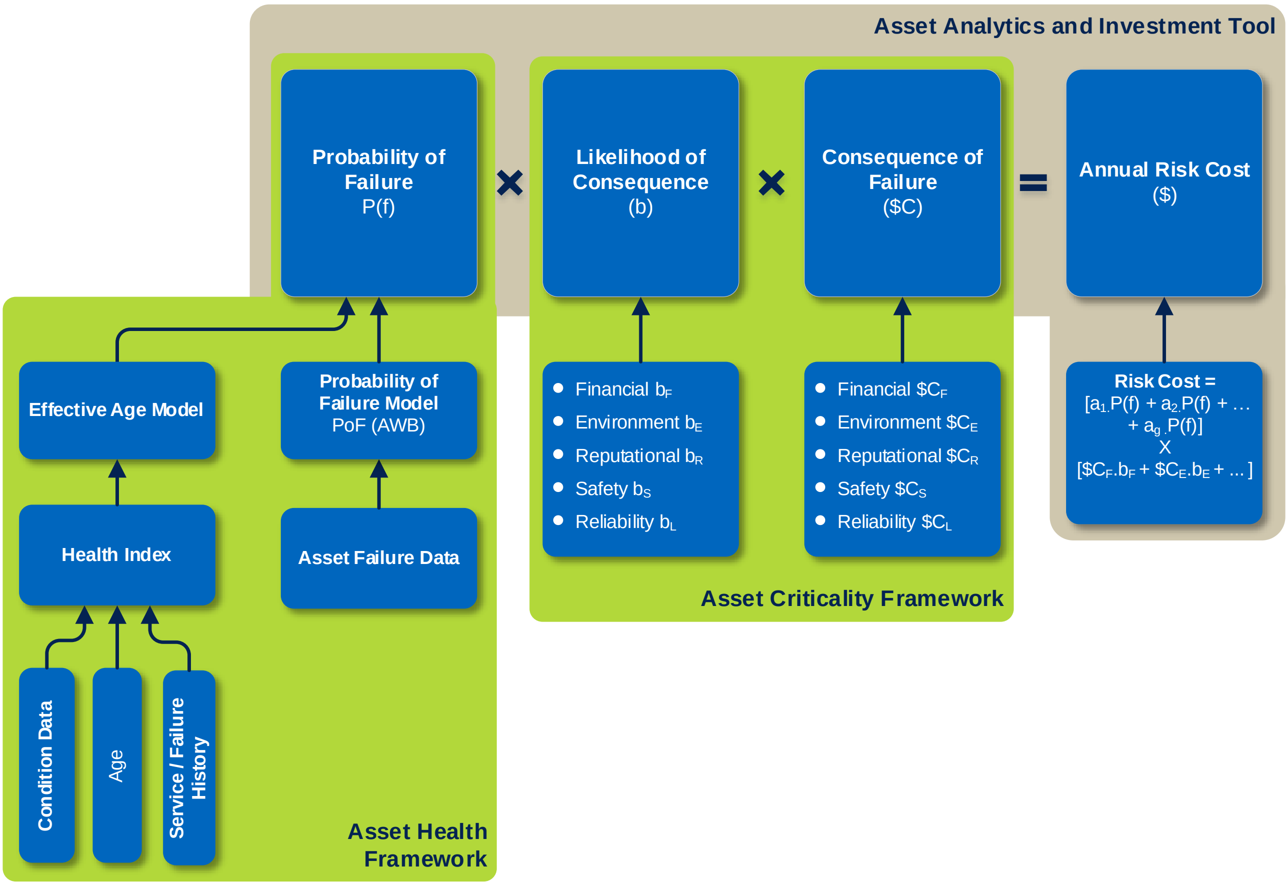
Appendix C Risk assessment framework

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[36] and its principles.

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 C-1 illustrates the base risk equation that we apply.

Figure C-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 and costs. The major quantified risks we apply for Repex justifications include asset failures that materialise as:

[36] Industry practice application note - Asset replacement planning, AER July 2024

- 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.