Transgrid

People. Power. Possibilities.

Maintaining compliance with performance standards applicable to Panorama substation secondary systems

RIT-T Project Assessment Conclusions Report

Date of issue: 22 August 2025

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining the safe and reliable operation of Panorama substation. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Panorama 132/66 kV substation comprises 2x 132 kV feeders, 2x 132/66/11 kV transformers and 5x 66 kV feeders. The site was established in 1979, and the secondary systems assets have installation dates ranging between 1979 and 2012. Panorama substation is a customer connection point supplying Essential Energy's 66 kV network in the area inclusive of Bathurst which contains Bathurst Correctional Centre and Hospitals.

Secondary systems assets at Panorama 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 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 Panorama 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]

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.

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, 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.

No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 24 January 2025 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

Developments since publication of the PSCR

At the time the PSCR was published, Transgrid's cost estimates for both options were primarily based on a desktop assessment of the activity required and based on market pricing from 2020. Transgrid has since undertaken detailed inspections of the site involving extensive walkthrough and review of constructability. The inspections determined the quantum and extent of site works required and coupled with updates to general equipment and contractor pricing has increased capital expenditure from the initial outline noted in the PSCR in January 2025.

Due to the issues described above, the cost estimates outlined in the PSCR ($11.36 million +/- 25 per cent for Option 1, and $9.80 million for Option 2) are not adequate to cover the scope and have been revised accordingly.

As a result of the detailed site constructability assessment and updated market conditions, the associated estimates proposed to remediate those issues has been revised to factor in:

- increase in construction efforts required as a result of detailed site inspections, and
- revision of pricing rates to reflect the latest market conditions.

The revised capital expenditure estimate is now $14.36 million +/- 25 per cent for Option 1, and $11.5 million +/- 25 per cent for Option 2. The financial risk cost estimate has also been updated to reflect the current extent of the condition issues and expected continued deterioration of the secondary systems, specifically the control system which is no longer serviceable.

No additional credible options were identified during the consultation period following publication of the PSCR. In addition, no material changes have occurred since the PSCR that have made an impact on the preferred option.

We have also updated our Value of Customer Reliability (VCR) to reflect the new estimates published by the AER as part of its 2024 VCR review.[4] On a statewide basis, the VCR values are lower than what we had used in the PSCR.

Option 2 remains the preferred option at this stage of the RIT-T process.

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).

Further, Transgrid does not consider social licence issues arise for this RIT-T.

Credible options considered

We consider there are two credible network option that would meet the identified need from a technical, commercial, and project delivery perspective.[5] These options are summarised in Table E-1 below.

Table E-1 Summary of the credible options

Option	Description	Estimated capex ($m, 2024/25 +/- 25%)	Operating costs ($ per year, $2024/25)
Option 1	Replace individual assets	14.36	16,814
Option 2	Complete in-situ renewal	11.5	7,360

[4] See: https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024.

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

Assets with deteriorating condition to be replaced include Protection Schemes, Control Systems and Metering Systems. See **Error! Reference source not found.** for a full list of assets to be replaced under Option 1 and Option 2.

No submissions received in relation to non-network options

In the PSCR we noted that 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. No submissions were received in response to the PSCR in relation to non-network options.

Conclusion: complete in-situ replacement is optimal

This PACR finds that implementation of Option 2 is the preferred option to address the identified need. Option 2 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, DC supply systems, and market meters 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 $11.5 million (in $2024/25). The works will be undertaken between 2024/25 and 2028/29. Planning, design, development and procurement (including the completion of the RIT-T) will occur between 2024/25 and 2026/27, while project delivery and construction will occur between 2027/28 and 2028/2029. All works are expected to be completed by 2028/29, with final commissioning of the solution expected in 2028/29 to best meet the need of meeting the service level required for protection schemes. Routine operating and maintenance costs are estimated to be approximately $7,360 per annum (in $2024/25).

Next steps

This PACR represents the final step of the consultation process in relation to the application of the Regulatory Investment Test for Transmission (RIT-T) process undertaken by Transgrid.

The second step of the RIT-T process, production of a Project Assessment Draft Report (PADR), was not required as Transgrid considers its investment in relation to the preferred option to be exempt from that part of the RIT-T process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the preferred option being less than $54 million;
- the PSCR stating:
  - 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 options 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;

- no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR addressing any issues raised in relation to the proposed preferred option during the PSCR consultation (noting that no issues have been raised).

Parties wishing to raise a dispute notice with the AER may do so prior to 20 September 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude. Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Panorama Secondary Systems PACR'.

Contents

1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining the safe and reliable operation of Panorama 132/66 kV substation. Publication of this Project Assessment Conclusions Report (PACR) is the final step in the RIT-T process.

Secondary systems assets at Panorama substation are impacted by technological obsolescence of the equipment, increasing the time to rectify defects and increasing the risk that primary assets at the substation may not be able to reliably operate.

The purpose of this RIT-T is to examine and consult on options to address the risk of secondary systems failure as a result of technological obsolescence at Panorama substation. 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 PACR[6] is to:

- describe the identified need;
- describe and assess credible options to meet the identified need;
- describe the assessment approach used; and
- provide details of the proposed preferred option to meet the identified need.

Overall, this report provides transparency into the planning considerations for investment options to ensure continuing reliable supply to our customers. A key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

1.2 No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 24 January 2025 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

1.3 Developments since the Project Specification Consultation Report

At the time the PSCR was published, Transgrid's cost estimates for both Options were primarily based on a desktop assessment of the activity required and based on market pricing from 2020. Transgrid has since undertaken detailed inspections of the site involving extensive walkthrough and review of constructability. The inspections determined the quantum and extent of site works required and coupled with updates to general equipment and contractor pricing has increased capital expenditure from the initial outline noted in the PSCR in January 2025.

[6] See Appendix A for the National Electricity Rules requirements.

Due to the issues described above, the cost estimates outlined in the PSCR ($11.36 million +/- 25 per cent for Option 1, and $9.80 million for Option 2) are not adequate to cover the scope and have been revised accordingly.

As a result of the detailed site constructability assessment and updated market conditions, the associated estimates proposed to remediate those issues has been revised to factor in:

- increase in construction efforts required as a result of detailed site inspections, and
- revision of pricing rates to reflect the latest market conditions.

The revised capital expenditure estimate is now $14.36 million +/- 25 per cent for Option 1, and $11.5 million +/- 25 per cent for Option 2. The financial risk cost estimate has also been updated to reflect the current extent of the condition issues and expected continued deterioration of the secondary systems, specifically the control system which is no longer serviceable.

No additional credible options were identified during the consultation period following publication of the PSCR. In addition, no material changes have occurred since the PSCR that have made an impact on the preferred option.

We have also updated our Value of Customer Reliability (VCR) to reflect the new estimates published by the AER as part of its 2024 VCR review.[7] On a statewide basis, the VCR values are lower than what we had used in the PSCR.

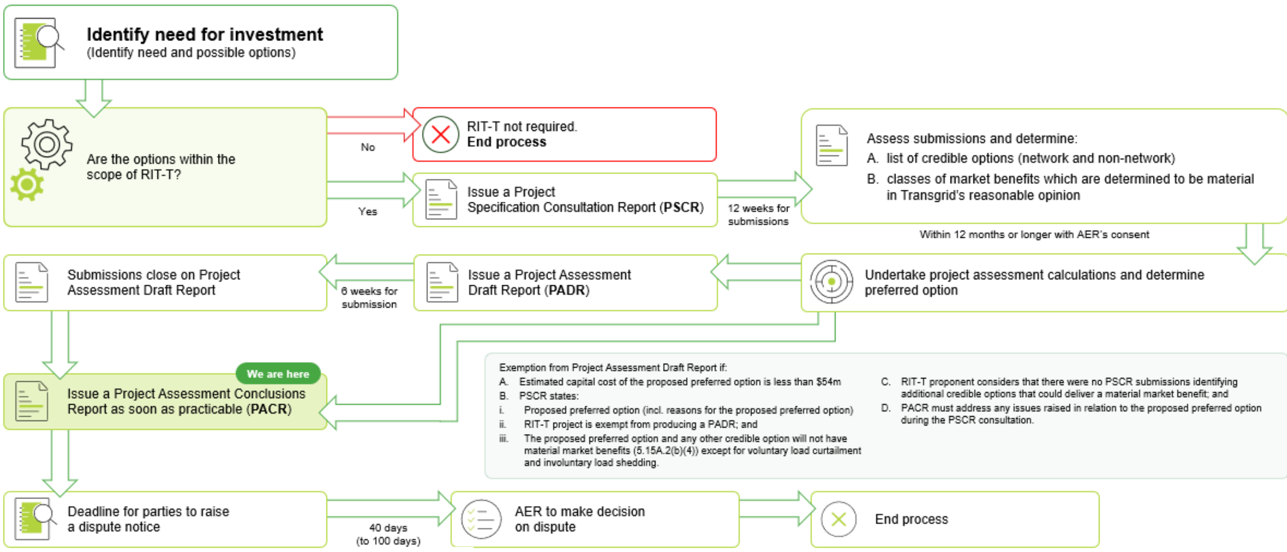
Option 2 remains the preferred option at this stage of the RIT-T process.

1.4 Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process undertaken by Transgrid. It follows the PSCR released in January 2025. No submissions were received in response to the PSCR.

[7] See: https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024.

Figure 1-1 This PACR is the final stage of the RIT-T process[8]



Parties wishing to raise a dispute notice with the AER may do so prior to 20 September 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude.

Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Panorama Secondary Systems PACR'.

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

2. The identified need

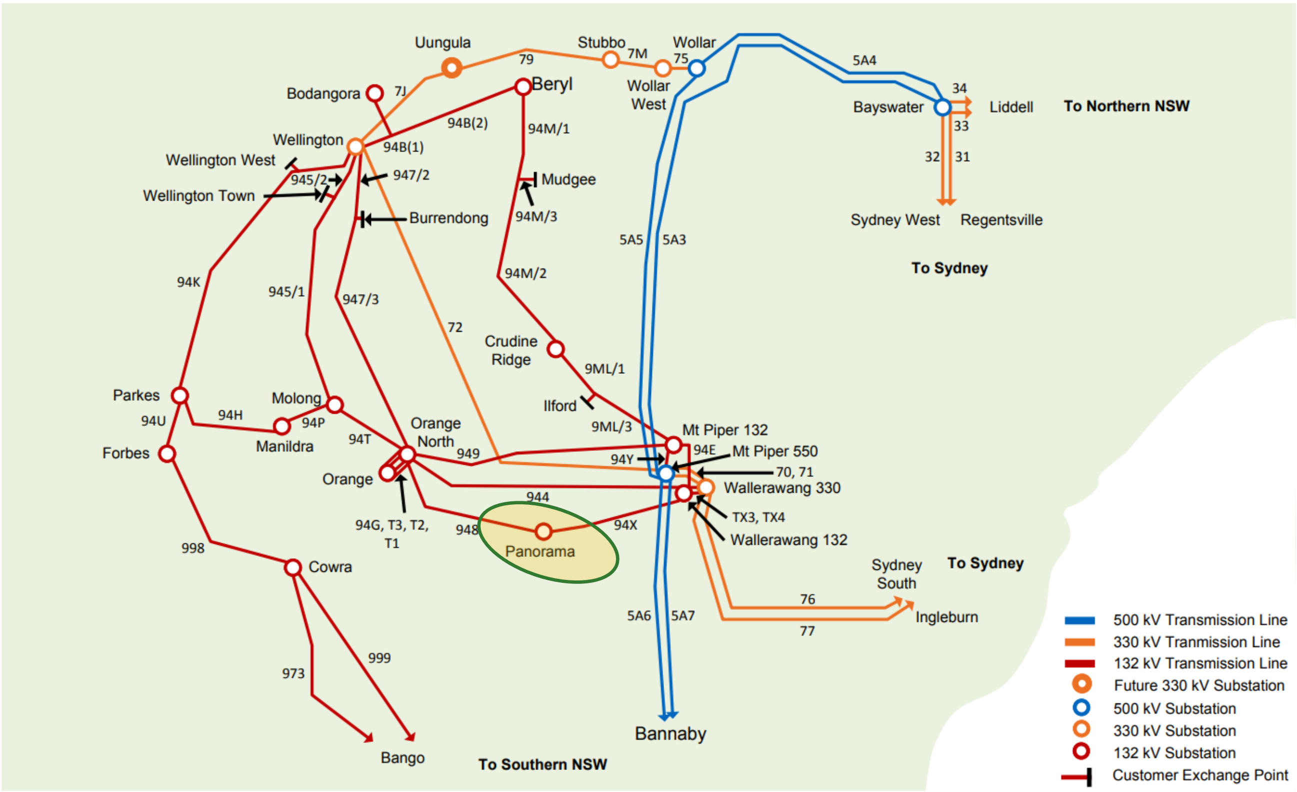
This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out background information related to the identified secondary systems.

2.1 Background to the identified need

The Panorama 132/66 kV substation serves the Panorama area and is located within Transgrid's Central West 132 kV subsystem. This substation comprises 2x 132 kV feeders, 2x 132/66/11 kV transformers, and 5x 66 kV feeders. The site was established in 1979, and the secondary systems assets have installation dates ranging between 1979 and 2012. Panorama substation is a customer connection point supplying Essential Energy's 66 kV network in the area inclusive of Bathurst which contains Bathurst Correctional Centre and Hospitals.

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

Figure 2-1 Location of Panorama 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.[9] 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 Panorama 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.[10] 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.[11]

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, 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

[9] As per Schedule 5.1 of the NER.
[10] As per S5.1.2.1(d) of the NER.
[11] AEMO. "Power System Security Guidelines, 3 June 2024 (DRAFT)." Melbourne: AEMO, 2024. Accessed 4 June 2024.

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.

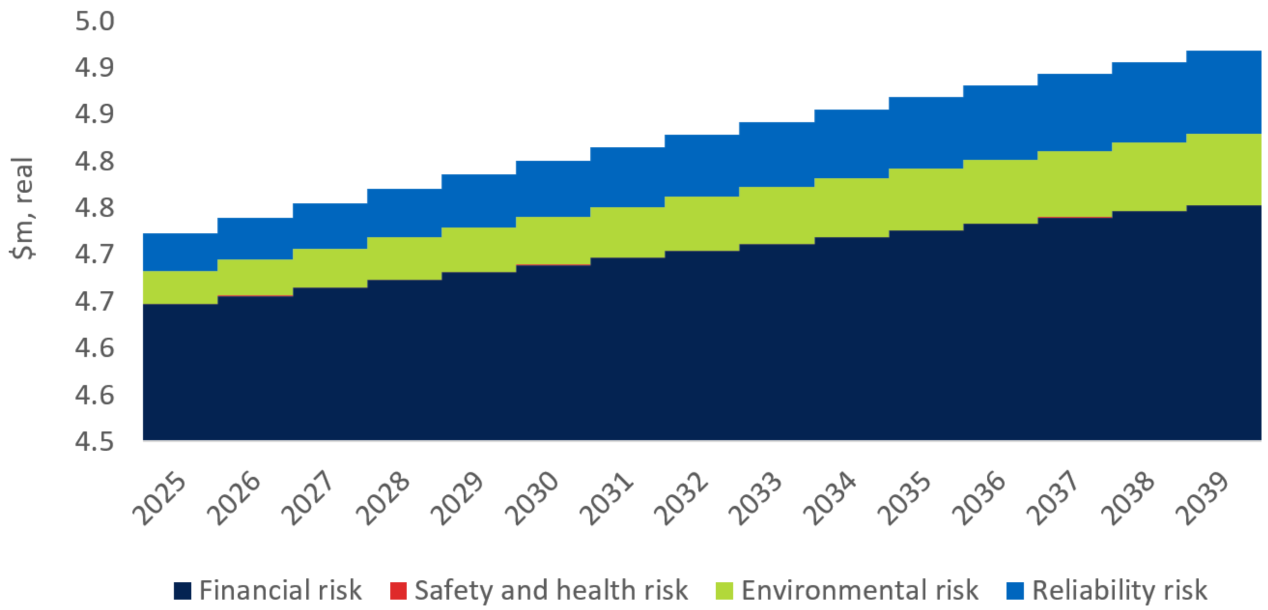
2.3 Assumptions underpinning the identified need

We adopt a risk cost framework to quantify and evaluate the risks and consequences of increased failure rates. **Error! Reference source not found.** 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 $4.72 million/year and it is expected to increase going forward if action is not taken and the secondary systems assets are left to deteriorate further (reaching approximately $4.92 million/year by the end of the 15-year analysis 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.[12]

22 protection relays at Panorama substation are targeted for replacement. A list of these relays can be found in **Error! Reference source not found.**. The effective age of these relays in 2027/28 ranges from 14 years to 54 years, with an average effective age of 36 years. In contrast, the typically useful life of a relay is around 15 years. Key issues presented by these relays are:

- 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.

85% of the protection relays 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[13] and maximum clearance times.[14]

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 Panorama 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 **Error! Reference source not found.**. The effective age in 2027/28 of these control systems is 27 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

[12] S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times
[13] NER, s5.1.2.1(d) and s5.1.9(c).
[14] NER, s5.1a.8.

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.[15]

2.3.1.3 Metering systems

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.

All meters at Panorama substation are being targeted for replacement. A list of these meters can be found in **Error! Reference source not found.**. The effective age of these meters in 2027/28 ranges from 15 years to 16 years, with an 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
- technology obsolescence resulting in a lack of spares and no manufacturer support.

These meters are at or beyond the end of their technical life. If not renewed to latest standards, this may result in future loss of accuracy and/or ability to measure energy throughput 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 97 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.

[15] NER, clause 4.11.1.

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 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 220 kV 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 PACR.

Reliability risk makes up 1 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 1 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

This section describes the options that we have explored to address the identified need, including the scope of each option and the associated costs.

We consider that there are two credible network options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need.[16] Four other options were considered but not progressed for reasons outlined in Table 3-5.

We do not consider non-network options to be technically feasible to provide the functionality of the equipment required for addressing the identified need in this RIT-T. No submissions were received in response to the PSCR in relation to non-network options.

The credible options considered are summarised in Table 3-1 below.

Table 3-1 Summary of credible options

Option	Description	Estimated capex ($m, 2024/25 +/- 25%)	Operating costs ($ per year, $2024/25)
Option 1	Replace individual assets	14.36	16,814
Option 2	Complete in-situ renewal	11.5	7,360

3.1 Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PACR 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 proactive capital investment is made to remediate the deterioration of the secondary systems assets at Panorama substation, or to 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 $20,263 in FY25, temporarily increasing to $121,837 in FY28 before decreasing back to $20,263 in FY32 for the rest of the 15-year assessment period (in $2024/25). The substantial increase in operating costs during FY28 to FY31 is due to building refurbishment works, which were necessary to address the rectification costs identified in the dilapidation reports.

The table below provides a breakdown of the expected operating expenditure under the base case.

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

Table 3-2 Breakdown of capital and operating expenditure under the base case ($2024/25)

Year	Capital cost ($m, 2024/25)	Operating costs ($2024/25, $ per year)
2025	-	20,263
2026	-	20,263
2027	-	20,263
2028	-	121,837
2029	-	121,837
2030	-	121,837
2031	-	121,837
2032	-	20,263
2033	-	20,263
2034	-	20,263
2035	-	20,263
2036	-	20,263
2037	-	20,263
2038	-	20,263
2039	-	20,263

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.

Under the base case, increases to the regular maintenance regime will not be able to mitigate the risk of asset failure due to continued deterioration in asset condition. This will lead to an increase in the probability of failure at Panorama substation. Rectification of asset failures will take longer due to the limited availability of spares and discontinued manufacturer support. This will lead to an increase in the duration of an outage when it occurs at Panorama substation.

These factors will increase the risk of prolonged and frequent involuntary load shedding for end-customers. We have estimated that the cost of involuntary load shedding due to asset failure at Panorama substation will increase from approximately $40,839 in 2024/25 to approximately $88,764 at the end of the 15-year assessment period (in $2024/25). The above factors will also expose us and our end-customers to greater environmental, safety and financial risks associated with catastrophic asset failure, such as increased risk of explosive failure resulting in injury to nearby people and collateral damage to nearby assets. We have estimated that environmental, safety and financial risks costs under the base case will be approximately $4.68million in 2024/25 and increase to $4.83 million at the end of the 15-year assessment period (in $2024/25).

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 **Error! Reference source not found.**.

The capital cost of this option is approximately $14.36 million (in $2024/25). The work will be undertaken in stages over the 15-year assessment period. This capital cost is comprised of $6.62 million in labour costs, $4.88 million in material costs, and $2.85 million in expenses.

The routine operating and maintenance costs are estimated at approximately $18,189 in FY25, temporarily decreasing to $17,914 in FY26 and $17,639 in FY27 before increasing to $118,937 in FY29. Operating costs then decrease to $16,814 in FY32 for the rest of the 15-year assessment period (in $2024/25). As mentioned above, the increase in operating expenditure 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	0.89	18,189
2026	0.89	17,914
2027	0.89	17,639
2028	0.89	118,937
2029	9.85	118,937
2030	-	118,937
2031	-	118,937
2032	-	16,814
2033	0.11	16,814
2034	-	16,814
2035	-	16,814
2036	-	16,814
2037	0.43	16,814
2038	-	16,814
2039	-	16,814

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 five-year period with all works expected to be completed by 2028/29. Planning, design, development and procurement (including the completion of the RIT-T) will occur between 2024/25 and 2026/27, while project delivery and construction will occur between 2027/28 and 2028/29. All works are expected to be completed by 2028/29, with final commissioning of the solution expected in 2028/29 to best meet the need of meeting the service level required for protection schemes.

The capital cost of this option is approximately $11.5 million (in $2024/25). This cost is comprised of $3.06 million of labour costs, $4.62 million in material costs, and $3.81 million in expenses.

The routine operating and maintenance costs are estimated at approximately $20,263 in FY25 before decreasing to $19,836 in FY26, $8,641 in FY26, and $8,214 in FY28. Operating costs reach $7,360 in FY29 and continue at this value for the rest 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	0.5	20,263
2026	0.5	19,836
2027	1.1	8,641
2028	6.9	8,214
2029	2.50	7,360
2030	-	7,360
2031	-	7,360
2032	-	7,360
2033	-	7,360
2034	-	7,360
2035	-	7,360
2036	-	7,360
2037	-	7,360
2038	-	7,360
2039	-	7,360

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 Building (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.
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.[18] 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:[19]

- 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.

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

[19] 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

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 be no 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.

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 PACR.

4. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the NER and whether they are considered material for this RIT-T.[20]

4.1 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 132/66/11 kV transformers at the Essential Energy BSP, 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.

4.2 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.[21]

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 Australia's greenhouse gas emissions
- 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.

[20] 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 (See: NER, clause 5.15A.2(5). See Appendix A Compliance checklist for requirements applicable to this document.

[21] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, November 2024, Melbourne: Australian Energy Regulator.

4.3 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 of the classes of market benefits listed below will be material for this RIT-T assessment for the reasons in Table 4-1.

Table 4-1 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.[22] 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.

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

5. 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.

5.1 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).[23] 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.[24] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest IASR).[25]

5.2 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[26]). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.[27]

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

23 AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.
24 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.
25 AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.
26 I.e., there is an equal likelihood of over- or under-spending the estimate total.
27 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.

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.

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).

5.3 Value of customer reliability

In the PSCR, we applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER.[28] Following preparation of the PSCR, the AER published its final report on the VCR values to apply from 2025 onwards. On a statewide basis, the VCR values are lower than what we had used in the PSCR. However, the change in VCR did not have any impact on the identification of the preferred option.

The estimated VCR for 2025 is $31,536/MWh.[29]

[28] AER, *Values of Customer Reliability, Final Report on VCR Values,* December 2024

[29] AER, *Values of Customer Reliability, Final Report on VCR Values,* December 2024. Escalated to a $2024/25 estimate using implied 6-month escalation rate of 1.96% derived from RBA February 2025 CPI forecast of 2.4% for the year end June 2025

5.4 The options have 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 PACR 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 **Error! Reference source not found.**.

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.[30]

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

Table 5-1 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)	$31,536/MWh	$31,536/MWh	$31,536/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

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

5.5 Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PACR 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
- 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.

6. Assessment of credible options

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. The benefits of each credible option are represented by a reduction in costs or risks compared to the base case.

All costs and benefits presented in this PACR are in 2024/25 dollars.

6.1 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 6-1 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	4.37	3.35	5.40	4.37
Option 2	34.80	26.17	43.43	34.80

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

6.2 Estimated costs

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

Table 6-2 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	9.21	9.21	9.21	9.21
Option 2	7.91	7.91	7.91	7.91

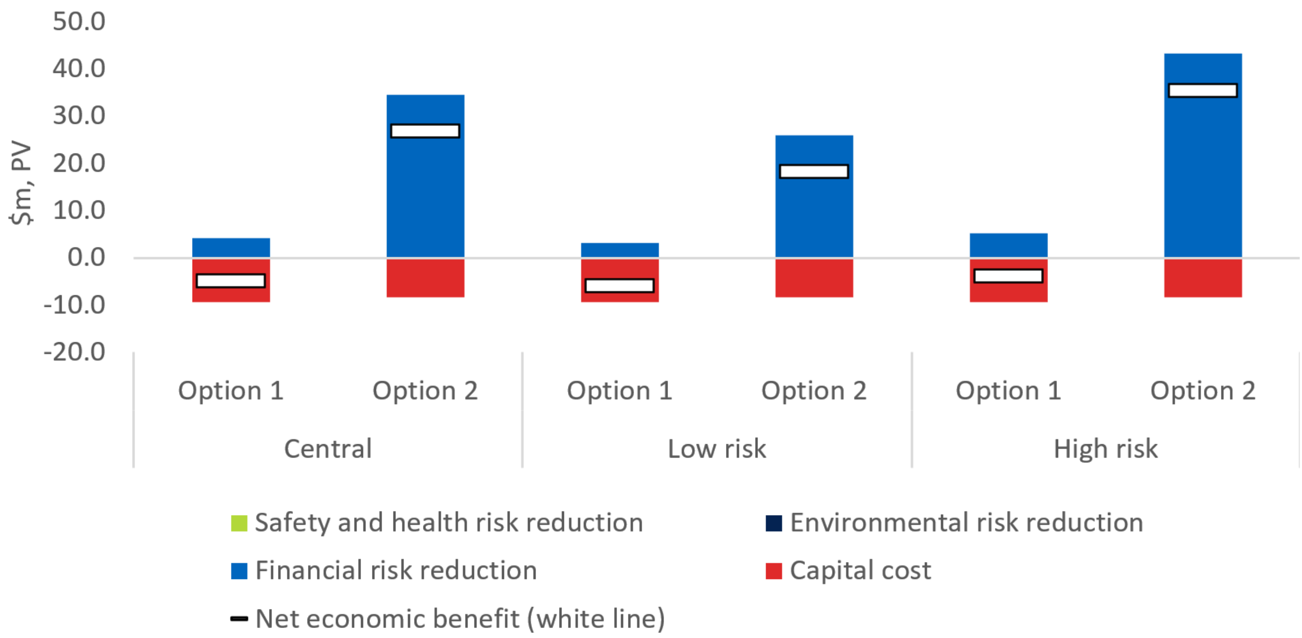
6.3 Estimated net economic benefits

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 6-3: 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	-4.84	-5.86	-3.82	-4.84
Option 2	26.89	18.26	35.52	26.89

Figure 6-1 NPV of net economic benefits ($2024/25 m)



6.4 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.

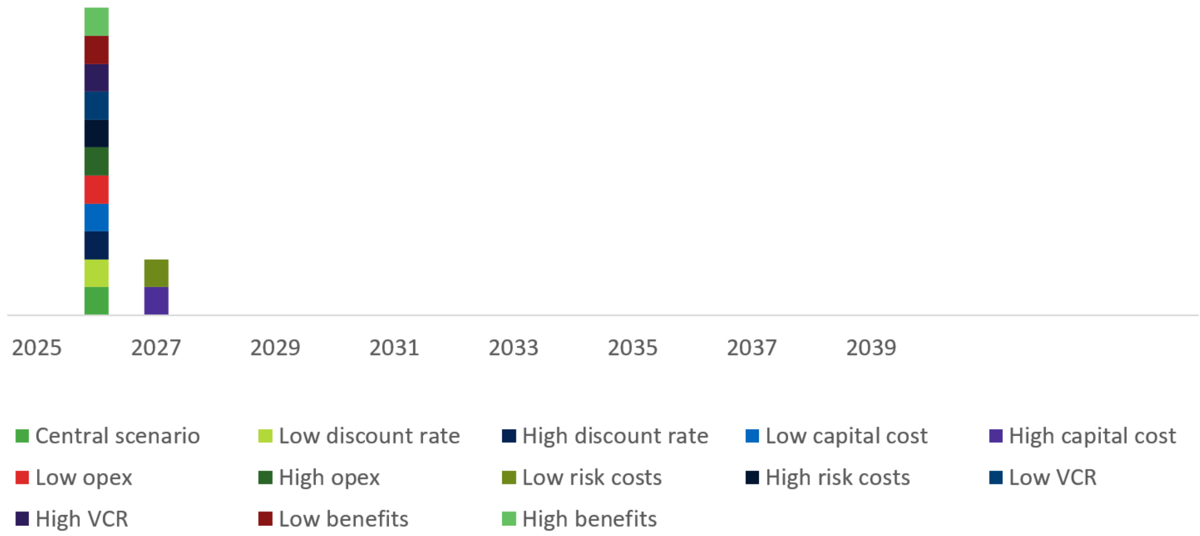
The application of the two steps to test the sensitivity of the key findings is outlined below.

6.4.1 Step 1 – Sensitivity testing of the 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 sensitivities undertaken on the central scenario (apart from a 25 per cent decrease in risk costs and a 25 per cent increase in capital costs).

Figure 6-2 below outlines the impact on the optimal commissioning year, under a range of alternative assumptions. For most alternative assumptions, the optimal commissioning date for Option 2 is found to be 2026/27. However, Transgrid has scheduled the asset's commissioning in 2028/29 to manage expenditure within the 2023-2028 regulatory period allowance, and to accommodate resourcing limitations and outage constraints. Commissioning in 2028/29 provides Transgrid with sufficient time to address technology obsolescence and maintain compliance with NER performance requirements for protection schemes. Progressive improvement of the protection schemes is expected as work is undertaken in stages over a five-year period to deliver Option 2.

Figure 6-2 Distribution of optimal timing under a range of different key assumptions



6.4.2 Step 2 – Sensitivity of the 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 safety, environmental and financial risks
- a 25 per cent increase/decrease in the assumed network capital costs; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.5 per cent;

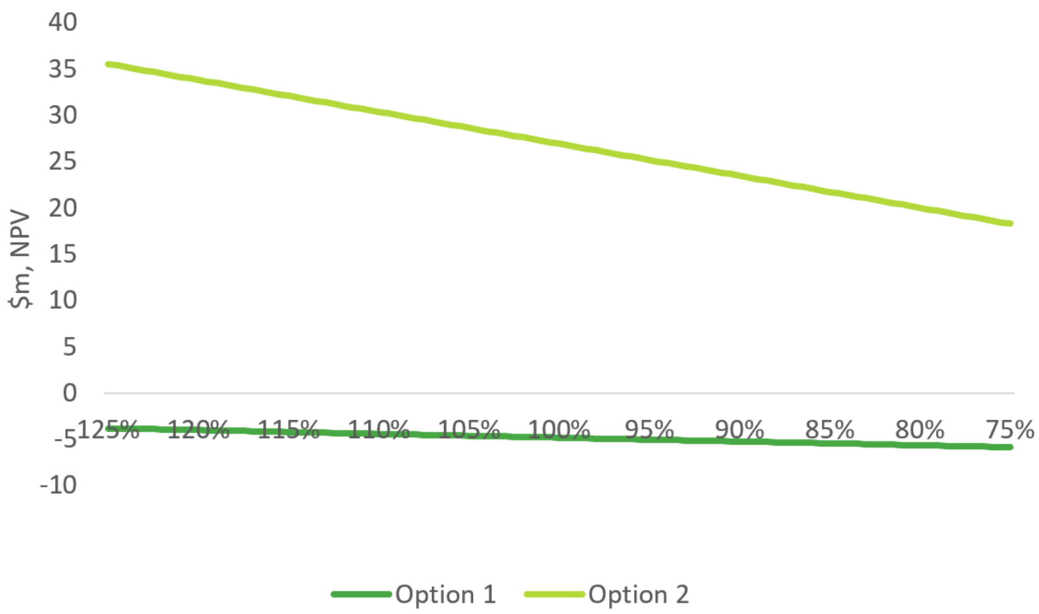
These sensitivities investigate the consequences of 'getting it wrong' having committed to a certain investment decision.

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting lower and higher risk values, which includes safety & health risk, environmental risk and financial risk. We estimated the net economic benefit of each option by adopting risk costs that is 25% higher (the 'High Risk scenario) and 25% lower (the 'Low Risk' scenario) than the estimate of risk adopted in our central scenario. The results of this analysis are presented in the table and figure below. No reasonable risk costs were identified that resulted in Option 1 breaking even.

Table 6-4 NPV of net economic benefits relative to the base case under a lower and higher risk costs ($2024/25 m)

Option/scenario	Lower Risk Cost	Higher Risk Cost	Ranking	Breakeven (%)
Sensitivity	75% of Central estimate	125% of Central estimate		
Option 1	-5.86	-3.82	2	N/A
Option 2	18.26	35.52	1	N/A

Figure 6-3 Sensitivity of net economic benefits under a lower and higher risk costs ($2024/25 m)

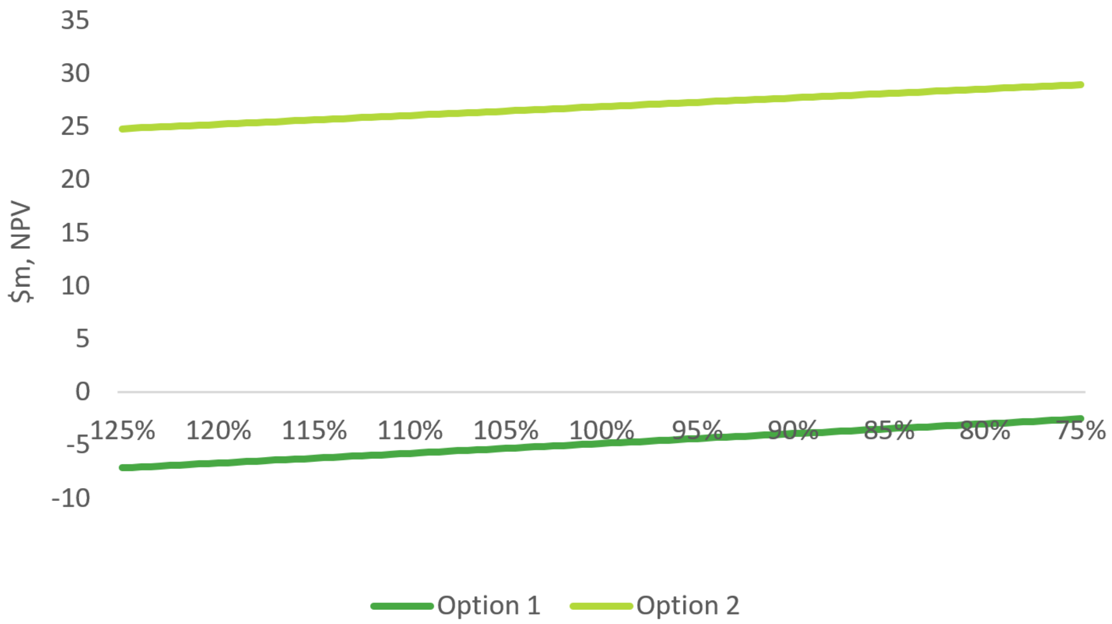


The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting lower and higher capital costs. We estimated the net economic benefit of each option by adopting capital costs for each option that are 25% higher (the 'High capex' scenario) and 25% lower (the 'Low capex' scenario) than the capital cost estimates in our central scenario. The results of this analysis are presented in the table and figure below. No reasonable capital costs were identified that resulted in Option 1 breaking even.

Table 6-5 Sensitivity of net economic benefits under lower and higher capital costs ($2024/25 m)

Option/scenario	Lower capex	Higher capex	Ranking	Breakeven (%)
Sensitivity	75% of Central estimate	125% of Central estimate		
Option 1	-2.53	-7.15	2	N/A
Option 2	28.97	24.81	1	N/A

Figure 6-4 Sensitivity of net economic benefits under lower and higher capital costs ($2024/25 m)



The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 3.63% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[31] and a high discount rate of 10.5% which aligns with the high discount rate scenario in the 2023 IASR (the 'High discount rate' scenario).[32] No reasonable discount rates were identified that resulted in Option 1 breaking even.

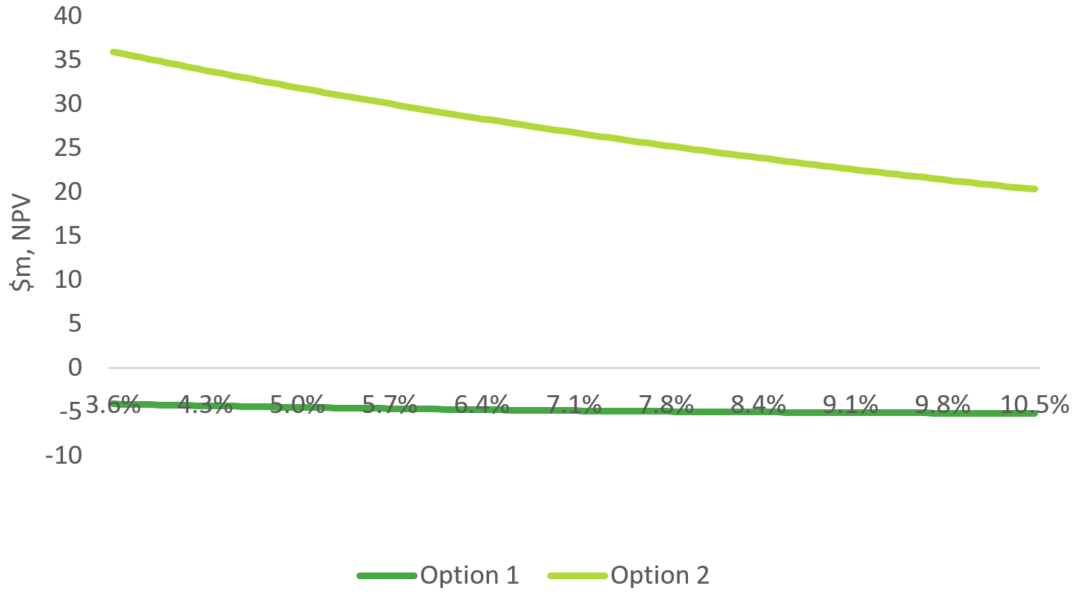
Table 6-6 Sensitivity of net economic benefits under a lower and higher discount rates ($2024/25 m)

Option/scenario	Lower discount rate	Higher discount rate	Ranking	Breakeven (%)
Sensitivity	3.63%	10.5%		
Option 1	-4.09	-5.15	2	N/A
Option 2	35.94	20.29	1	N/A

31 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: AER, TasNetworks – 2024-29 – Final decision – PTRM, April 2024, WACC sheet.

32 AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

Figure 6-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2024/25 m)



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 decrease by -1969 per cent;
- the estimated risk costs (in aggregate) would need to fall by 104 per cent; and
- no reasonable discount rate would result in Option 2 no longer being the preferred Option.

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

7. Final conclusion on the preferred option

This PACR finds that Option 2 is the preferred option to address the identified need. This is because Option 2 is expected to deliver net benefits of approximately $26.89 million, whereas Option 1 is expected to deliver net benefits of approximately -$4.84 million. Option 2 involves replacement of all secondary systems assets at the site.

The capital cost of this option is approximately $11.5 million (in $2024/25). The works will be undertaken between 2024/25 and 2028/29. Planning, design, development and procurement (including the completion of the RIT-T) will occur between 2024/25 and 2026/27, while project delivery and construction will occur between 2027/28 and 2028/29. All works are expected to be completed by 2028/29, with final commissioning of the solution expected in 2028/29 to best meet the need of meeting the service level required for protection schemes. Routine operating and maintenance costs are estimated to be approximately $7,360 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 cost inputs, estimated risk costs and underlying discount rates, noting that there would need to be unrealistic changes to these key assumptions to change the ranking of the options (as shown via the boundary testing at the end of section 6). 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.

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 233.

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(v)	The project assessment conclusions report must set out:	–
	(1) the matters detailed in the project assessment draft report as required under paragraph (k); and	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (q).	NA
5.16.4(k)	The project assessment draft report must include:	–
	(1) a description of each credible option assessed;	3
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	NA
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	3 & 6
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	4 & 5
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	4
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	NA
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	6
	(8) the identification of the proposed preferred option;	7
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	3 & 7
	(10) if each of the following apply to the RIT-T project:	N/A

	(i) if the estimated capital cost of the proposed preferred option is greater than $100 million[33] (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, The RIT-T reopening triggers applying to the RIT-T project.	
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[34] (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.	1

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	Relevant Section(s)
3.1	In all cases, it is essential that RIT-T proponents express the identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. This objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in RIT-T reports, as opposed to being implicit.	2.2
3.2.5	A RIT-T proponent must consider social licence issues in the identification of credible options. There are many potential sources of information when considering how this should be done, which include community sentiment data, prior experience, best practices, relevant guidelines, and early engagement with consumers, stakeholders and communities.	3.5 & 5.2
3.4	Except for specific circumstances, RIT-T proponents must adopt the inputs, assumptions and scenarios from the most recent inputs, assumptions and scenarios report (IASR).	5.1

[33] Varied to $103m based on the AER Final Determination: Cost threshold Review published November 2024 (see: 2024 RIT and APR cost threshold review - final determination - 12 November 2024.pdf) .

[34] Varied to $54m based on the AER Final Determination: Cost threshold Review published November 2024 (see: 2024 RIT and APR cost threshold review - final determination - 12 November 2024.pdf) .

3.4.1	The RIT-T specifies that: (iii) The RIT-T proponent must adopt the discount rate from the most recent inputs, assumptions and scenarios report unless it provides demonstrable reasons why a variation is necessary. If the RIT-T proponent decides to vary this parameter, this variation must be consistent with paragraph 19. (iv) The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used must be consistent with the cash flows being discounted. (v) Consistent with the RIT-T requirement, present value calculations in the ISP must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. Given this consistency, it should be suitable for RIT-T proponents to apply the discount rate that AEMO has applied in the most recent ISP.	5.1
3.5	In the RIT-T, costs are the present value of a credible option's direct costs. These must include the following classes of costs: • Costs incurred in constructing or providing the credible option. • Operating and maintenance costs over the credible option's operating life. For clarity, a consequence of this is that, if the modelling period is shorter than the life of the credible option, the RIT-T proponent would incorporate the operating and maintenance costs (if any) for the remaining years of the credible option into the terminal value. • Costs of complying with relevant laws, regulations and administrative requirements. • A RIT-T proponent must exclude from its analysis, the costs (or negative benefits) of a credible option's harm to the environment or to any party that is not prohibited under the relevant laws, regulations or legal instruments, with the exception of changes in Australia's greenhouse gas emissions.	5.2 & 5.3
3.5A.1	Where the estimated capital costs of the preferred option exceeds $100 million[35] (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: (i) 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 (ii) 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
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: (iii) all key inputs and assumptions adopted in deriving the cost estimate (iv) a breakdown of the main components of the cost estimate (v) the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates)	3 & 5

[35] Varied to $103m based on the AER Final Determination: Cost threshold Review published November 2024 (see: [2024 RIT and APR cost threshold review - final determination - 12 November 2024.pdf]) .

	(vi) the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied (vii) the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	
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.	3.5 & 5.2
3.6.1	Under the RIT-T instrument, a RIT-T proponent must include all classes of market benefits unless: • it can provide reasons for why a particular class of market benefit is unlikely to materially affect the outcome of the credible options assessment, or • it expects the cost of undertaking the analysis to quantify the market benefits will be disproportionate to the scale, size and potential benefits of the credible options.	4
3.6.2	Under the RIT-T instrument, a RIT-T proponent must also consider classes of market benefits that: • the RIT-T proponent determines relevant, and • we have agreed to in writing before the RIT-T proponent publishes its consultation report.	4.3
3.7.1	For each credible option, a RIT-T proponent must develop two states of the world (one with the credible option in place and the other being the base case with no option in place) for each reasonable scenario. This allows the RIT-T proponent to later derive the market benefits of an option by comparing these states of the world, and then probability weighting those benefits across a range of reasonable scenarios.	5.1
	All assets and facilities that exist during a RIT-T application must, at least initially, form part of all relevant states of the world (both with and without the credible option in place and in all reasonable scenarios). Beyond taking account of existing assets and facilities, a state of the world must capture the future evolution of and investment in generation, network and load. To capture this, the RIT-T instrument requires the RIT-T proponent to include appropriate: • Committed projects: these must form part of all states of the world, consistent with the treatment of existing assets and facilities. • Actionable ISP projects: these must form part of all states of the world, consistent with the treatment of committed projects unless the level of analysis required to include the actionable ISP project is disproportionate to the scale and likely impact of the credible options under consideration. • Anticipated projects: the RIT-T proponent must use the ISP, and where absent from the ISP, its reasonable judgement to include these in all relevant states of the world. • Modelled projects: appropriate market development modelling will determine which modelled project to include in a given state of the world. For completeness, where a RIT-T proponent adopts the market modelling from the most recent ISP, ISP projects that are not actionable ISP projects (that is, future ISP projects and ISP development opportunities) will usually be modelled projects.	NA
3.8.1	Where no scenarios from the ISP are relevant to the RIT-T application, the RIT-T proponent must form reasonable scenarios consistently with the requirements for reasonable scenarios in the RIT-T instrument.	5.5
	Under the RIT-T instrument, the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. Specifically, the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect:	

	• the ranking of the credible options, where the identified need is for reliability corrective action, inertia network services or system strength services. In these cases, only the ranking (as opposed to the sign) of credible options' net economic benefits is important; and • the ranking or sign of the net economic benefit of any credible option where the identified need is not for reliability corrective action, inertia network services or system strength services. In these cases, the preferred option must have a positive net economic benefit.	
3.8.2	Where the estimated capital cost of the preferred option exceeds $100 million[36] (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
3.9.1	The methodology for assigning probabilities to each reasonable scenario must be consistent with the methodology for choosing the reasonable scenarios themselves. Where a RIT-T proponent has no evidence or rationale for assigning a higher probability for one reasonable scenario over another, it may weight all reasonable scenarios equally. Moreover, where the RIT-T proponent uses the most recent ISP scenarios as its reasonable scenarios, it must adopt the probability weightings that AEMO used in the most recent ISP.	5.5
3.9.2	A RIT-T proponent must separately undertake a weighted averaging of the direct costs of a credible option as well as the market benefits of a credible option.	5.5
3.9.3	The RIT-T instrument requires RIT-T proponents to consider option value as a class of potential market benefit.	4.3
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
3.11.2	While there are no specific requirements for the level of information required of concessional finance agreements at the RIT-T stage of a project, enough information must be provided to justify an agreement's inclusion. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate	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	3.5

[36] Varied to $103m based on the AER Final Determination: Cost threshold Review published November 2024 (see: 2024 RIT and APR cost threshold review - final determination - 12 November 2024.pdf) .

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 1

Item	Asset
Protection Relays	66 kV Bus Section 1 – No1 Protection 66 kV Bus Section 1 – No2 Protection 66 kV Bus Section 2 – No1 Protection 66 kV Bus Section 2 – No2 Protection Line 948 132 kV – No1 Protection Line 948 132 kV – No2 Protection Line 94X 132 kV – No1 Protection Line 94X 132 kV – No2 Protection Line 81L 66 kV – No1 Protection Line 81L 66 kV – No2 Protection Line 81C 66 kV – No1 Protection Line 81C 66 kV – No2 Protection Line 81F 66 kV – No1 Protection Line 81F 66 kV – No2 Protection Line 81G 66 kV – No1 Protection Line 81G 66 kV – No2 Protection Line 81H 66 kV – No1 Protection Line 81H 66 kV – No2 Protection Transformer 1 132 kV – No1 Protection Transformer 1 132 kV – No2 Protection Transformer 2 132 kV – No1 Protection Transformer 2 132 kV – No2 Protection Capacitor 1 66 kV – No1 Protection Capacitor 1 66 kV – No2 Protection Capacitor 2 66 kV – No1 Protection Capacitor 2 66 kV – No2 Protection
Control Systems	Sitewide Bay Controller Site SCADA Gateway 110V DC Supply A 110V DC Supply B
Metering Systems	Line 81L 66 kV – Revenue Metering Line 81C 66 kV – Revenue Metering Line 81F 66 kV – Revenue Metering Line 81G 66 kV – Revenue Metering Line 81H 66 kV – Revenue Metering Capacitor 1 and 2 66 kV – Revenue Metering Transformer 1 66 kV – Check Metering

Item	Asset
	Transformer 2 66 kV Check Metering

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

Table B-2 Protection Schemes considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
66 kV Bus Section 1 – 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.
66 kV Bus Section 1 – No2 Protection	53	
66 kV Bus Section 2 – No1 Protection	53	
66 kV Bus Section 2 – No2 Protection	53	
Line 948 132 kV – No1 Protection	37	
Line 948 132 kV – No2 Protection	37	
Line 94X 132 kV – No1 Protection	37	
Line 94X 132 kV – No2 Protection	37	
Line 81L 66 kV – No1 Protection	37	
Line 81L 66 kV – No2 Protection	37	
Line 81C 66 kV – No1 Protection	37	
Line 81C 66 kV – No2 Protection	37	
Line 81F 66 kV – No1 Protection	37	
Line 81F 66 kV – No2 Protection	37	
Line 81G 66 kV – No1 Protection	53	
Line 81G 66 kV – No2 Protection	53	
Line 81H 66 kV – No1 Protection	53	
Line 81H 66 kV – No2 Protection	53	
Transformer 1 132 kV – No1 Protection	15	
Transformer 1 132 kV – No2 Protection	15	
Transformer 2 132 kV – No1 Protection	15	
Transformer 2 132 kV – No2 Protection	15	
Capacitor 1 66 kV – No1 Protection	14	

Capacitor 1 66 kV – No2 Protection	13	
Capacitor 2 66 kV – No1 Protection	14	
Capacitor 2 66 kV – 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 Panorama 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	15	
110V DC Supply – No2 Battery	15	
110V DC Supply – No1 Charger	15	
110V DC Supply – No2 Charger	15	

Table B-4 presents a list of Metering Systems considered under this RIT-T. We have identified the following Metering Systems at Panorama substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-4 Metering Systems considered under this RIT-

Asset	Effective age (as at 2027/28)	Key issues
Line 81L 66 kV – Revenue Metering	16	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
Line 81C 66 kV – Revenue Metering	16	
Line 81F 66 kV – Revenue Metering	16	
Line 81G 66 kV – Revenue Metering	16	
Line 81H 66 kV – Revenue Metering	16	
Capacitor 1 and 2 66 kV – Revenue Metering	15	
Transformer 1 66 kV – Check Metering	16	
Transformer 2 66 kV Check Metering	16	

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 948 132 kV – No1 Protection Line 948 132 kV – No2 Protection Line 94X 132 kV – No1 Protection Line 94X 132 kV – No2 Protection Line 81L 66 kV – No1 Protection Line 81L 66 kV – No2 Protection Line 81C 66 kV – No1 Protection Line 81C 66 kV – No2 Protection Line 81F 66 kV – No1 Protection Line 81F 66 kV – No2 Protection Line 81G 66 kV – No1 Protection Line 81G 66 kV – No2 Protection Transformer 1 132 kV – No1 Protection Transformer 1 132 kV – No2 Protection Transformer 2 132 kV – No1 Protection Transformer 2 132 kV – No2 Protection Capacitor 1 66 kV – No1 Protection Capacitor 2 66 kV – No1 Protection
Control Systems	110V DC Battery A 110V DC Battery B
Metering Systems	Line 81L 66 kV – Revenue Metering Line 81C 66 kV – Revenue Metering Line 81F 66 kV – Revenue Metering Line 81G 66 kV – Revenue Metering Line 81H 66 kV – Revenue Metering Capacitor 1 and 2 66 kV – Revenue Metering Transformer 1 66 kV – Check Metering Transformer 2 66 kV Check Metering

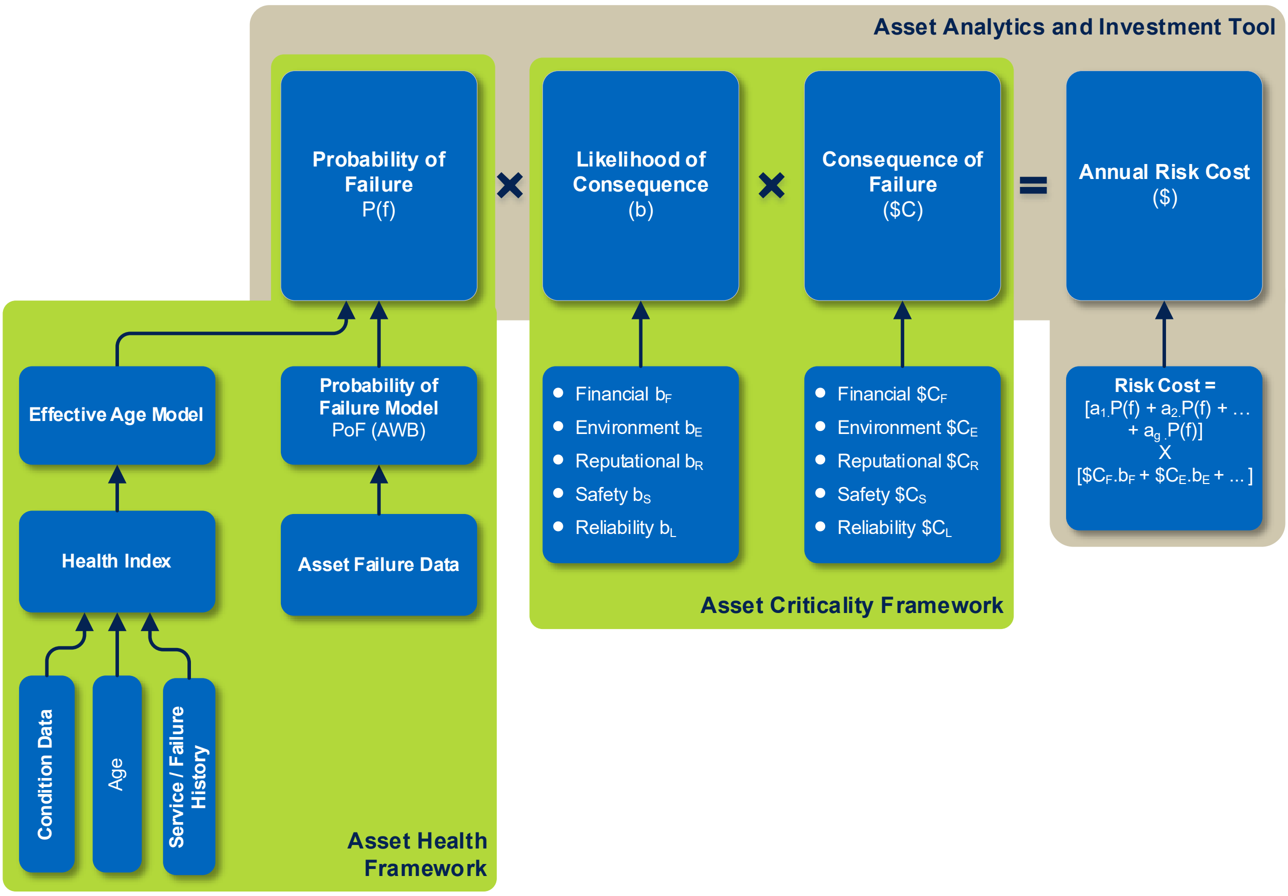
Appendix C Risk assessment framework

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[37] 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:

37 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 2.3.

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

Appendix D Asset Health and Probability of Failure

The first step in calculating the probability of failure of an asset is determining the Asset Health and associated effective age,[38] which considers:

- An asset consists of different components, each with a particular function, criticality, 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. The 'Current effective age' is derived from asset information and condition data.
- Future effective age is linearly applied from assessed effective age.

The Probability of Failure (PoF) is the likelihood that an asset will fail during a given period resulting in a particular adverse event. The outputs of the Probability of Failure (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 assets are summarised in the table below.

Table D-1 Weibull parameters for assets

Asset	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
Protection Relay - Intertrip	26.2	1.54
Remote Terminal Unit	22.5	1.77
PC	12.7	2.09
Meter - Microprocessor	15.5	1.74
DC Battery	16.5	1.49
DC Charger	19.8	1.24

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