Transgrid

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Maintaining Safe and Reliable Operation of Murray substation

RIT-T Project Assessment Consultation Report

Region: Southern NSW

Date of issue: 2 April 2024

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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 Murray Substation. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Murray 330 kV substation is an ex-Snowy Mountains Hydro-electric Authority site which was commissioned in 1964. Murray substation connects approximately 1500 MW of renewable hydro-electric energy generation, supports four 330kV transmission lines in the southern New South Wales network, and provides electricity flow paths between the Snowy Mountains and Victoria. The 132kV network connects Guthega Hydro (60MW), Jindabyne Pumping Station, Munyang and Cooma Substation.

The substation is expected to continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. As a major generation and state interconnector connection point, Murray substation supports transmission through the entire NEM.

The condition of certain 330 kV and 132 kV high voltage and secondary system assets at Murray substation has deteriorated over time, leading to an increasing risk of failure which could result in reliability, safety, environment and financial consequences. The secondary systems assets are also impacted by 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.

Identified need: ensure the safe and reliable operation of Murray substation

The identified need for this project is to maintain the safe and reliable operation of Murray substation and the broader transmission network in NSW by addressing the risk of failure of certain high voltage and secondary systems at the substation.

Condition assessments performed through our routine maintenance program has shown degradation in the condition of these high voltage and secondary systems assets which will increase their risk of failure. Without intervention, other than ongoing business-as-usual maintenance, the assets are expected to deteriorate further and more rapidly. This will increase the risk of supply interruptions to our customers as well as safety, environmental and financial consequences.

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

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the net benefits that are expected to be generated for end-customers. However, the options considered in this PACR will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case), including obligations set out in Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 19 December 2023 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

No material developments since publication of the PSCR

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.

On 21 September 2023, the National Energy Laws were amended to reflect the incorporation of emissions reductions within the National Energy Objectives (NEO).[1] Following this the AEMC made harmonising changes to the National Electricity Rules, prompted by a rule change request from energy ministers, to ensure that network investment and planning frameworks are consistent with the new emissions reduction objective. The AEMC's Final Determination, published on 1 February 2024, included introducing a 'changes in Australia's greenhouse gas emissions' as a new class of market benefit to be considered within the RIT-T process.[2]

Transgrid supports greater consideration of emissions reduction within network planning and investment frameworks. These changes enable network planning and investment frameworks to support the achievement of the Commonwealth Government's net zero targets. Transgrid has set our own science-based targets to cut emissions and decarbonise our business. These include:

- Reducing Scope 1 and 2 emissions by 60 per cent by 2030, compared with a base year of 2021 and net zero by 2040.
- Reducing Scope 3 emissions from Purchased Goods and Services, and Capital Goods by 48 per cent for every million dollars that we spend on these two categories by 2030, compared with a base year of 2021, and net zero by 2050.[3]

For this RIT-T assessment, we do not consider there to be any material change to greenhouse gas emissions under the proposed preferred option, as only one credible option has been identified at this stage of the RIT-T. Therefore, we have not undertaken modelling of this market benefit for this assessment as there would be no change to the outcome of the RIT-T.

Option 1 remains the preferred option at this stage of the RIT-T process.

Credible options considered

We have identified one credible network option that meets the identified need from a technical, commercial, and project delivery perspective.[4] This option is summarised in the below. Three other options were considered (refurbishment of individual assets, asset retirement, and non-network solutions) but not

[1] Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023 (SA)

[2] AEMC, Harmonising the national energy rules with the updated national energy objectives – final determination, 1 February 2024

[3] For more information on Transgrid's planned journey to net zero please see our website here: https://www.transgrid.com.au/about-us/our-approach/our-journey-to-net-zero

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

progressed. The reasons for not progressing these options are outlined in Table 3-6. This option is summarised in the below.

Table E-1 Summary of the credible options

Option	Description	Capital costs ($M, 2023-24)	Operating costs ($M/yr, 2023-24)
Option 1	Targeted replacement of high voltage and secondary system assets	21.79	0.009

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

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

Item	Asset
Transformers	No1 Transformer No2 Transformer No1 Auxiliary Transformer No2 Auxiliary Transformer No3 Auxiliary Transformer
Protection relays	No1 & No2 Transformer No1 Protection Relay No1 & No2 Transformer No2 Protection Relay 330kV No1 Section A Bus No1 Protection Relay 330kV No2 Section A Bus No1 Protection Relay 330kV No1 Section B Bus No1 Protection Relay 330kV No2 Section B Bus No1 Protection Relay 97G/1 Geehi Tee No1 Protection Relay 97G/1 Geehi Tee No2 Protection Relay
Switchboard	415V AC Switchboard and Distribution System 11kV Switchboard including Protection and Metering 11kV Switchgear Building with auxiliary services

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

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

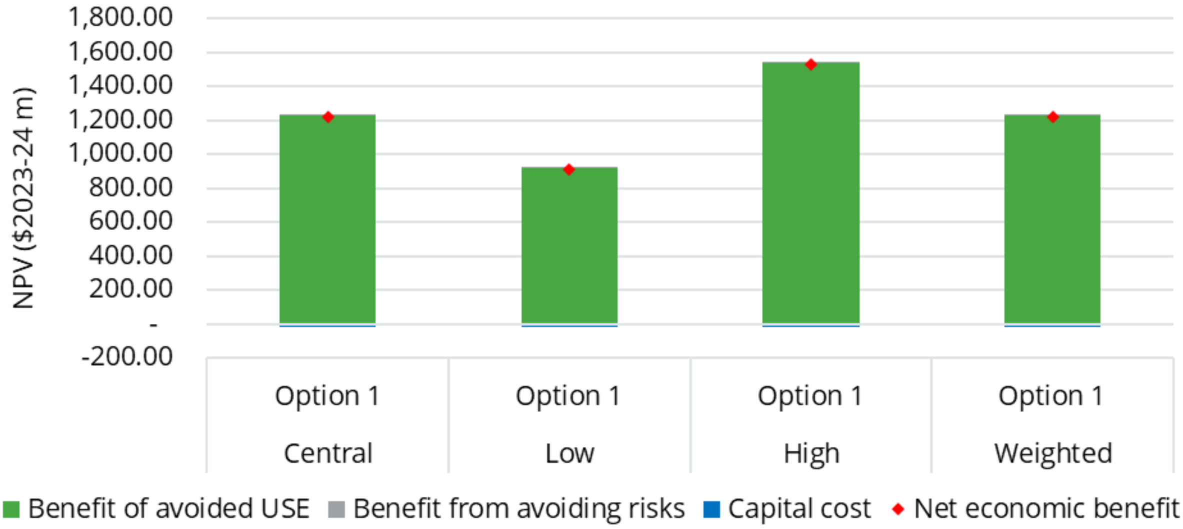
Option 1 delivers the highest net economic benefit and will meet NER requirements

We have assessed that Option 1 is net beneficial under all three reasonable scenarios considered in this PACR. On a weighted basis, where each scenario is weighted equally, Option 1 is expected to deliver net benefits of approximately $1,221.34 million[5]. Option 1 will also enable us to meet a range of obligations

[5] Approximately 99% of the overall net benefit is made up of reliability risk. This is due to both high voltage transformers at the Murray substation having effective ages beyond their technical life. As the assets continue to age the probability of one or both of the transformers failing increases. This increased probability of failure combined with a long load restoration time and

under the NER and jurisdictional instruments (which is not expected to be the case under the base case), including obligations set out in Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

Figure E-1 NPV of net economic benefits ($2023/24 m)



Conclusion

This PACR finds that Option 1 is the preferred option to address the identified need. Option 1 involves targeted replacement of high voltage and secondary system assets at Murray substation that have deteriorating condition and have reached (or will soon reach) the end of their technical lives and for which only limited manufacturer support and spares are available.

The capital cost of this option is approximately $21.79 million (in $2023-24). The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated at approximately $0.01 million per annum (in $2023-24).

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. It follows a PSCR released in December 2023. No submissions were received in response to the PSCR.

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 $46 million;
- the PSCR stating:

large industrial loads, means that there is likely to be significant amounts of unserved energy over the assessment period without replacement of the assets.

- 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.

Parties wishing to raise a dispute notice with the AER may do so prior to 6 May 2024 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 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 'Murray substation renewal 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 Murray substation. Publication of this Project Specification Consultation Report (PACR) is the first step in the RIT-T process.

Murray substation will continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. As a major generation and state interconnector connection point, Murray Substation supports transmission through the entire NEM.

The condition of certain 330 kV and 132 kV high voltage and secondary system assets at Murray substation has deteriorated over time leading to an increasing risk of failure which could result in reliability, safety, environment and financial consequences. The secondary systems assets are also impacted by 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 PACR is to examine and consult on options to address the deterioration of the high voltage and secondary systems asset condition and the risk from technology obsolescence of the secondary systems at Murray substation.

1.1 Purpose of this report

The purpose of this PACR[6] is to:

- describe the identified need;
- summarise the submissions received to the Project Specification Consultation Report (PSCR);
- 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 and there have been no material developments

We published a Project Specification Consultation Report (PSCR) on 19 December 2023 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

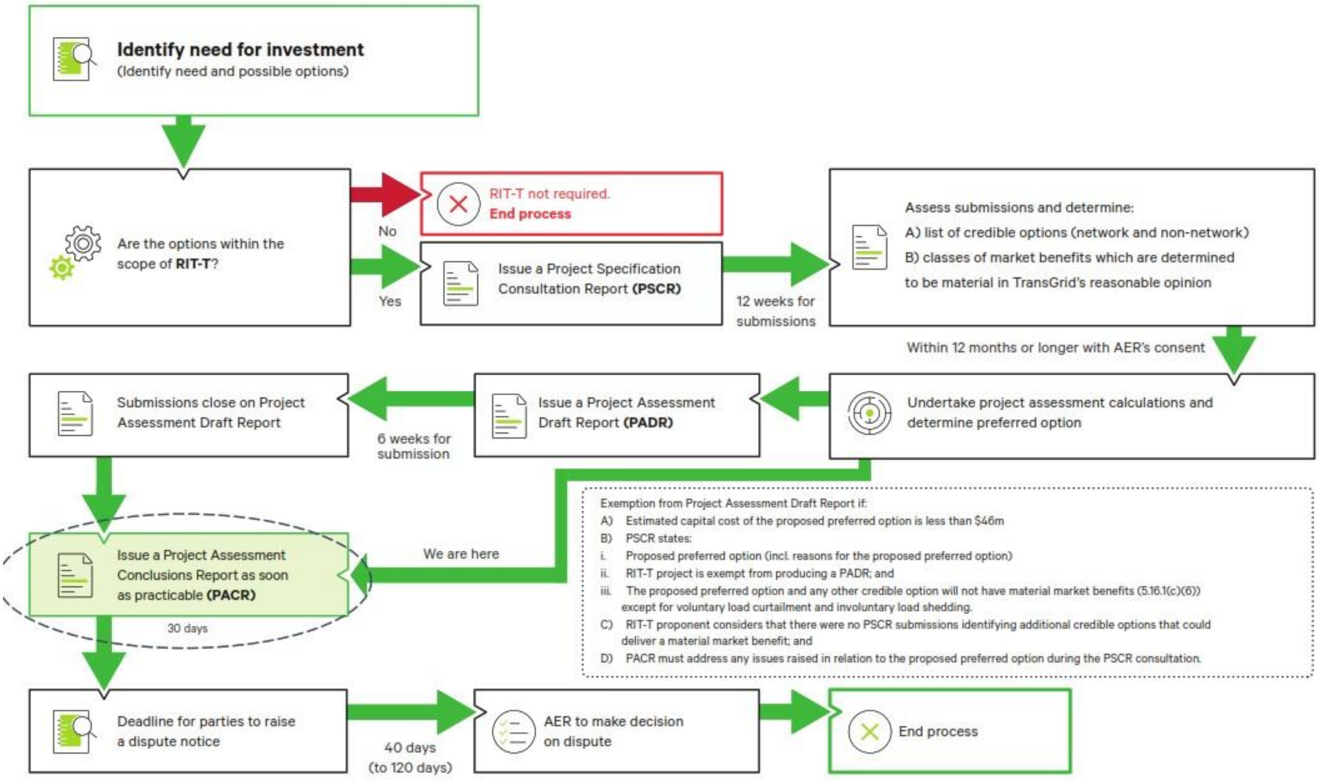
In addition, no additional credible options were identified during the consultation period following publication of the PSCR. No other material changes have occurred since the PSCR that have made an impact on the preferred option.

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

1.3 Submissions and 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. It follows a PSCR released in December 2023.

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



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 $46 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.

Parties wishing to raise a dispute notice with the AER may do so prior to 6 May 2024 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 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 'Murray substation renewal PACR'.

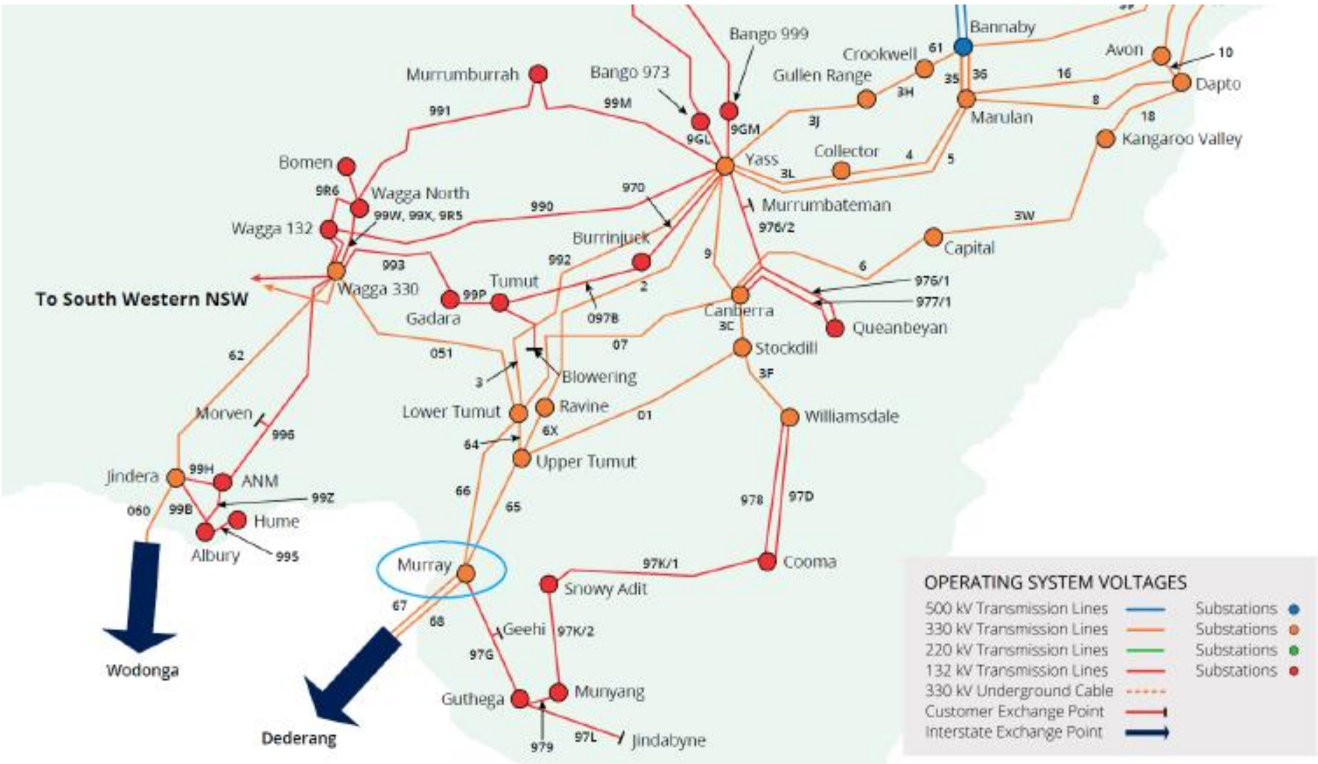
2. The identified need

2.1 Background to the identified need

Murray 330 kV substation is an ex-Snowy Mountains Hydro-electric Authority site which was commissioned in 1964. Murray substation connects approximately 1500 MW of renewable hydro-electric energy generation, supports four 330kV transmission lines in the southern New South Wales network, and provides electricity flow paths between the Snowy Mountains and Victoria. The 132kV network connects Guthega Hydro (60MW), Jindabyne Pumping Station, Munyang and Cooma Substation.

A map showing the location of Murray substation on our network is shown in Figure 2-1.

Figure 2-1 Location of Murray substation



Murray substation will continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. As a major generation and state interconnector connection point, Murray substation supports transmission through the entire NEM.

2.2 Description of the identified need

The identified need for this project is to maintain the safe and reliable operation of Murray substation and the broader transmission network in NSW by addressing the risk of failure of certain high voltage and secondary systems at the substation.

Condition assessments performed through our routine maintenance program has shown degradation in the condition of these high voltage and secondary systems assets which will increase their risk of failure. Without intervention, other than ongoing business-as-usual maintenance, the assets are expected to

Official

deteriorate further and more rapidly. This will increase the risk of supply interruptions to our customers as well as safety, environmental and financial consequences.

Power transformers are primary equipment that are essential for a safe and reliable electricity transmission, as they enable different voltage levels throughout the transmission and distribution networks. If the deteriorating asset condition of the power transformers is not addressed the likelihood of prolonged and involuntary load shedding in the Southern region will increase. Rectifying the worsening condition of the transformers will also reduce safety risks, as well as lower planned and unplanned corrective maintenance costs.

Secondary systems are used to control, monitor, protect and provide communication to facilitate safe and reliable network operation. They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur. A failure of the secondary systems would require replacement of the failed component and/or taking the affected primary assets, such as lines and transformers, out of service. Increasing failure rates, along with the increased time to rectify defects due to the obsolescence of the equipment, significantly affects the availability and reliability of the secondary systems at Murray substation and their ability to continue to meet the requirements of the NER.

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the net benefits that are expected to be generated for end-customers.

However, the options considered in this PACR will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case).

In particular, s5.1.2.1(d) requires TNSPs to 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. 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.[7] Under s5.1.9(c), TNSPs must provide sufficient primary and back-up protection systems, including breaker fail protection systems and any communications facilities on which the protection systems depend, to ensure that a fault of any type anywhere on our transmission system is automatically disconnected.

2.3 Assumptions underpinning the identified need

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

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

Figure 2-2 summarises the increasing risk costs over the assessment period under the base case.

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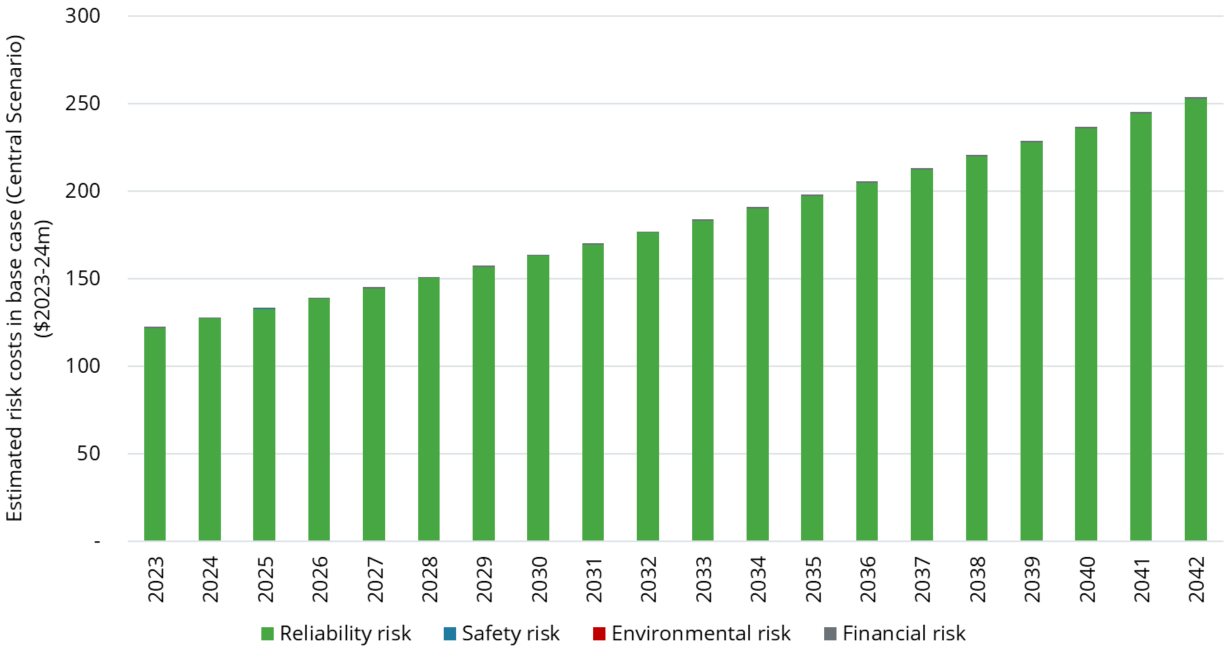
7 AEMO, *Power System Security Guidelines*, 6 February 2023, p.33.

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



This section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. The aggregate risk cost under the base case is currently estimated at around $120 million/year and it is expected to increase going forward if action is not taken and the transformers are left to deteriorate further (reaching approximately $200 million/year by 2036 and just over $250 million/year by the end of the 20-year assessment period).

2.3.1 Asset health and the probability of failure

2.3.1.1 Power transformers and auxiliary transformers

Power transformers are essential for a safe and reliable electricity transmission as they enable different voltage levels throughout the transmission and distribution networks. The Murray substation connects to 330kV, 132kV, 11kV and 415V networks.

We have identified the following power transformers at Murray substation with condition deterioration for replacement.

Table 2-1 Current transformers considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
No. 1 Power Transformer	59	Condition deterioration including multiple oil leaks, poor oil quality and moisture Offload tapchangers No. 1 Power Transformer bushings considerably older than useful life No.2 Power Transformer bushings near end of useful life
No. 2 Power Transformer	60	
No. 1 Auxiliary Transformer	65	
No. 2 Auxiliary Transformer	65	
No. 3 Auxiliary Transformer	28	

Power transformers and auxiliary transformers at Murray substation have reached the end of their economic lives. Owing to the configuration of the switchyard, under certain outage conditions, there is a lack of earthing, which is a significant safety issue. There are several ways this can be addressed, however one of the solutions is to replace the auxiliary transformers with a model that provides an earth. As power transformers age, the following conditions materialise which increase the risk of asset failure:

- Degradation of the high voltage bushings and paper insulation system due to electrical stress
- Oil leaks due to degradation of seals and outer housing
- Lack of voltage control due to offload tap changers

If left unreplaced, continued degradation in the condition of the asset will significantly increase the risk of asset failure and the risk of unplanned network outages. There will be an increased cost to replace the assets upon failure in a reactive fashion. A failure can also pose serious safety and environmental hazards. A failure of the power transformers can result in the risk of injuring people, cause collateral damage and outages of nearby services, and other environmental issues such as fires. Replacing the power transformers at Murray substation will reduce the risk of involuntary load shedding for customers in southern NSW, and reduce the risk of safety and environmental hazards associated with any catastrophic failures occurring.

2.3.1.2 Protection relays

Protection relays are assets the monitor the network and trip circuit breakers when an abnormality in operating conditions is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the NER.[8]

We have identified the following protection relays at Murray substation are experiencing increasing failure rates, manufacturer obsolescence and a lack of support and are targeted for replacement.

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

Table 2-2 Protection relays considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
No1 & No2 Transformer No1 Protection Relay	17	Exceeded technical life and relay type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support
No1 & No 2 Transformer No2 Protection Relay	15	
330kV No1 Section A Bus No1 Protection Relay	67	
330kV No2 Section A Bus No1 Protection Relay	67	
330kV No1 Section B Bus No1 Protection Relay	67	
330kV No2 Section B Bus No1 Protection Relay	67	
97G/1 Geehi Tee No1 Protection Relay	14	
97G/1 Geehi Tee No2 Protection Relay	13	

The protection relays are approaching or have exceeded the end of their technical life by the end of the 2023-28 regulatory period. 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 components. Replacement of the protection relays is required to ensure compliance with the NER, including requirements around maintaining adequate protection systems[9] and maximum clearance times.[10]

2.3.1.3 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.

The No1 and No2 transformer AVR controllers are new assets required for the deployment of new transformers with tap changer capabilities.

[9] NER, s5.1.2.1(d) and s5.1.9(c).
[10] NER, s5.1a.8.

2.3.1.4 Switchboards

Switchboards provide all switchyard functionality such as circuit breakers, instrument transformers, disconnectors and earth switches in series of joined metal enclosed bays for each switchyard service (e.g. transformer supply or feeder supply). Switchboards are typically used at lower voltages and installed indoors in dedicated switchrooms or buildings with all bays supplied as a package from a single original equipment manufacturer.

We have identified the following switchboard assets at Murray substation are experiencing increasing failure rates, manufacturer obsolescence and a lack of support and are targeted for replacement.

Table 2-3 Switchboards and gear considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
415V AC Switchboard and distribution system	65	Exceeded technical life and experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support
11 kV Switchboard including protection and metering	61	Exceeded technical life and experiencing increased failure rates. Arc fault containment hazards limit access causing increased cost to stage site works around the existing switchboard. Building design not suitable to withstand arc fault over-pressure. Technology obsolescence resulting in a lack of spares and no manufacturer support
11kV Switchgear building with auxiliary services	61	

The 415V switchboard has failed, interim repairs have been completed to restore supply. The 415V switchboard supplies all critical and non-critical systems at the site including DC supplies, GPOs, lighting, air conditioners, security, and transformer cooling. It will remain an integral asset for the foreseeable future.

The existing 11kV switchboard was designed without internal arc classifications and the associated arc flash hazard assessment has identified extensive exclusion areas while the switchboard is in-service. This risk cannot be effectively mitigated with equipment modifications.

Coupled with the advanced age and technology obsolescence of a majority of 11kV switchboard components, the 11kV switchboard and associated assets have reached the end of their technical life.

Scope development has identified 11kV switchboard and building replacement as the most effective scope of works. This scope significantly benefits from lower works costs associated with managing staging required to control arc flash hazards when working on or near the existing 11kV switchboard compared to retaining the 11kV switchboard with some arc flash mitigation works.

2.3.1.5 Circuit breakers

The failure of a circuit breaker to operate during a network fault will result in an uncleared fault that must be cleared with a larger outage (via a circuit breaker failure back up protection operation), leading to greater unserved energy. The impact of each circuit breaker failure on lost load varies according to where it is located in the network. Asset failure may also increase the risk of safety and environment issues associated with catastrophic asset failure, and the potential costs of emergency repair and replacements.

We note that circuit breakers at the Murray substation have previously been considered under our 'Managing the risk of circuit breaker failure' RIT-T process as part of a network wide circuit breaker replacement program. We have therefore not considered the impact of a failure of the circuit breakers at the Murray substation in this PACR. This avoids any potential double counting of the benefits related to the replacement of the circuit breakers.

2.3.2 Reliability risk

We have considered the risk of unserved energy for customers following a failure of one or more of the high voltage and secondary systems assets identified in this PACR. The likelihood of a consequence takes into account the likelihood of contingent planned/unplanned outages, the anticipated load restoration time (based on the expected time to undertake any repair work), and the load at risk (based on forecast demand). The monetary value is based on an assessment of the value of customer reliability, which measures the economic impact to affected customers of a disruption to their electricity supply.

Reliability risk makes up over 99 per cent of the total estimated risk cost in present value terms. The relative size of this risk is due to both high voltage transformers at the Murray substation having effective ages beyond their technical life. As the assets continue to age the probability of one or both of the transformers failing increases. This increased probability of failure combined with a long load restoration time and large industrial loads, means that there is likely to be significant amounts of unserved energy over the assessment period without replacement of the assets.

2.3.3 Safety risk

This refers to the safety consequence to staff, contractors and/or members of the public of an asset failure. The likelihood of a consequence takes into account the frequency of workers on-site, the duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. The monetary value takes into account the cost associated with fatality or injury compensation, loss of productivity, litigation fees, fines and any other related costs.

We manage and mitigate safety risk to ensure they are below risk tolerance levels or 'As Low As Reasonably Practicable' ('ALARP'), in accordance with our obligations under the *New South Wales Electricity Supply (Safety and Network Management) Regulation 2014* and our Electricity Network Safety Management System (ENSMS). Consistent with our ALARP obligations, we apply a disproportionality factor of 'six' to the public safety component and 'three' to the worker safety component of safety risk.

Safety risk makes up less than 1 per cent of the total estimated risk cost in present value terms.

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 takes into account 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 bushfires. The monetary value takes into account 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 less than 1 per cent of the total estimated risk cost in present value terms.

2.3.5 Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence takes into account any compliance and regulatory factors which are not covered by the other categories. The monetary value takes into account the cost associated with disruption to business operations, any third party liability, and the cost of replacement or repair of the asset, including any temporary measures.

Financial risk makes up less than 1 per cent of the total estimated risk cost in present value terms.

3. Options that meet the identified need

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

We consider that there is only one technically and commercially feasible option to address the identified need.[11] This involves targeted replacement of the high voltage and secondary systems assets at Murray substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence. This option is summarised in the table below. We do not consider non-network options to be technically or commercially feasible to assist with meeting the identified need for this RIT-T. Furthermore, no submissions regarding the potential of non-network options to satisfy, or contribute to satisfying, the identified need for this RIT-T were received in response to the PSCR publication.

Table 3-1 Summary of credible options

Option	Description	Estimated capex ($M, 2023-24)	Expected commission date (Financial year)
1	**Targeted replacement of high voltage and secondary systems assets at Murray substation**	**21.79**	
	Transformers	10.85	2028
	Auxiliary Transformers	2.00	2028
	11kV switchboard	4.52	2028
	Protection	0.80	2028
	Control	3.62	2028

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.:[12]

> “*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 high voltage and secondary systems assets at Murray 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.

11 As per clause 5.15.2(a) of the NER.
12 AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p. 21.

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

Table 3-2 Breakdown of operating expenditure under the base case (($M, 2023-24))

Item	Operating expenditure ($M, 2023-24)
Transformers	0.003
Auxiliary Transformers	0.002
Switchboard	0.003
Protection	0.001
Control	0
Total	**0.009**

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 Murray 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 Murray 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 Murray substation will increase from approximately $120 million in 2023/24 to approximately $250 million in 2041/42 (in $2023-24). 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 $660,000 in 2023/24 and increase to $810,000 in 2041/42 (in $2023-24).

3.2 Option 1 – Targeted asset replacement at Murray substation

Option 1 involves targeted replacement of high voltage and secondary system assets at Murray substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence. The option is based on a like-for-like replacement approach whereby the asset is replaced by its modern equivalent. The assets that will be replaced under this option are set out in the table below.

Table 3-3 Assets to be replaced under Option 1

Item	Asset
Transformers	No1 Transformer No2 Transformer No1 Auxiliary Transformer No2 Auxiliary Transformer No3 Auxiliary Transformer
Protection relays	No1 & No2 Transformer No1 Protection Relay No1 & No2 Transformer No2 Protection Relay 330kV No1 Section A Bus No1 Protection Relay

	330kV No2 Section A Bus No1 Protection Relay 330kV No1 Section B Bus No1 Protection Relay 330kV No2 Section B Bus No1 Protection Relay 97G/1 Geehi Tee No1 Protection Relay 97G/1 Geehi Tee No2 Protection Relay
Switchboard	415V AC Switchboard and Distribution System 11kV Switchboard including Protection and Metering 11kV Switchgear Building with auxiliary services

Overall, the work will be undertaken over a five-year period with all works expected to be completed by the end of 2027/28. The capital cost of this option is approximately $21.79 million (in $2023-24). Table 3-4 below provides a breakdown of the estimated capital cost by asset type, while Table 3-5 breaks down the capital cost according to whether the cost will be labour, material or expenses.

Table 3-4 Capital cost of Option 1 by asset type ($M, 2023-24)

Capital cost	2023-24[13]	2024-25	2025-26	2026-27	2027-28
Transformers	0.447	0.615	2.167	5.395	2.223
Auxiliary Transformers	0.078	0.112	0.402	0.994	0.413
Switchboard	0.190	0.257	0.905	2.246	0.927
Protection	0.033	0.045	0.157	0.402	0.168
Control	0.145	0.201	0.727	1.799	0.749
Total	**0.894**	**1.229**	**4.357**	**10.836**	**4.480**

Table 3-5 Capital cost of Option 1 by labour, expenses and materials ($M, 2023-24)

Capital cost	Labour	Expenses	Materials
Total	6.264	7.204	8.352

The routine operating and maintenance costs are estimated at approximately $0.01 million per annum (in $2023-24). We expect that the new protection relays and control systems will have an asset life of 15 years, the switchboard will have an asset life of 40 years and transformers will have an asset life of 45 years.

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 in order to complete the works with minimal impact on the network.

Implementation of Option 1 is expected to reduce the probability of failure for high voltage and secondary systems at Murray substation. This will reduce the frequency and duration of involuntary load shedding associated with the failure of these assets. Option 1 will also reduce the risk of asset failure, which will in turn reduce associated environmental, safety and financial risk costs.

[13] Includes concept design work

3.3 Options considered but not progressed

We have also considered whether other options could meet the identified need. Reasons these options were not progressed are summarised in Table 3-6.

Table 3-6 Options considered but not progressed

Option	Reason(s) for not progressing
Refurbishment of individual assets	This option is not technically feasible due to the specialised skillsets required and the inability to resolve the lack of support from manufacturers.
Asset retirement	This option 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.

3.4 No material inter-network impact is expected

We have considered whether the credible options listed above are expected to have material inter-regional impact.[14] 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.*"[15]

By reference to AEMO's screening test for an inter-network impact,[16] a material inter-regional impact may arise if a credible option:

- is expected to change power transfer capability between transmission networks or in another TNSP's network by more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- is expected to result in an increase in fault level by more than 10 MVA at any substation in another TNSP's network; or
- involves either a series capacitor or modification in the vicinity of an existing series capacitor.

As none of these criteria are satisfied for this RIT-T, we consider that there are no material inter-network impacts associated with any of the credible options considered.

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

[15] Definition of 'material inter-network impact,' in the Glossary to the NER.

[16] 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 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

4. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the National Electricity Rules (NER) and whether they are considered material for this RIT-T.[17]

4.1 Avoided unserved energy is material

We consider that changes in involuntary load shedding are expected to be material for the credible options outlined in this PACR. In the base case, involuntary load shedding would be expected to occur following a failure of the high voltage or secondary systems assets at Murray substation which would require taking affected primary assets, such as lines and transformers, out of service.

The probability of asset failure is expected or increase over time as the condition of the relevant assets continue to deteriorate. This is expected to increase the frequency of outages. Rectification of asset failures will take longer due to the limited availability of spares and discontinued manufacturer support. This is expected to increase the duration of outages.

We have estimated expected unserved energy under the base case and Option 1. These forecasts are based on probabilistic planning studies of failure rates and repair times. Option 1 significantly reduces the amount of expected unserved energy that would occur. The avoided unserved energy for a credible option is calculated as the difference between the expected unserved energy under the base case and the expected unserved energy under Option 1.

4.2 Wholesale electricity market benefits are not material

The AER has recognised that if the credible options 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.

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

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

[17] The NER requires that all classes of market benefits identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or classes) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.16.4(k)(5). See Appendix A for requirements applicable to this document

4.3 No other categories of market benefits are material

In addition to the classes of market benefits identified above, the NER also requires us to consider the following classes of market benefits, listed in Table 4-1, arising from each credible option.[18] We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons in Table 4-1.

Table 4-1: Reasons non-wholesale electricity market benefits categories are considered not material

Market benefits	Reason
Differences in the timing of unrelated network expenditure	The credible options considered are unlikely to affect decisions to undertake unrelated expenditure in the network. Consequently, material market benefits will neither be gained nor lost due to changes in the timing of expenditure from any of the options considered.
Option value	We note the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[19] We also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T.[20] We do not consider there to be any option value with the options considered in this PACR. Additionally, a significant modelling assessment would be required to estimate the option value benefits which would be disproportionate to the potential additional benefits for this RIT-T. Therefore, we have not estimated additional option value benefit.
Changes in network losses	We do not expect any material difference in transmission losses between options.

On 21 September 2023, the National Energy Laws were amended to reflect the incorporation of emissions reductions within the National Energy Objectives (NEO).[21] Following this the AEMC made harmonising changes to the National Electricity Rules, prompted by a rule change request from energy ministers, to ensure that network investment and planning frameworks are consistent with the new emissions reduction objective. The AEMC's Final Determination, published on 1 February 2024, included introducing a 'changes in Australia's greenhouse gas emissions' as a new class of market benefit to be considered within the RIT-T process.[22]

Transgrid supports greater consideration of emissions reduction within network planning and investment frameworks. These changes enable network planning and investment frameworks to support the achievement of the Commonwealth Government's net zero targets. Transgrid has set our own science-based targets to cut emissions and decarbonise our business. These include:

[18] NER, clause 5.15A.2(b)(4)-(6).
[19] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.57-58.
[20] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.57-58.
[21] Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023 (SA)
[22] AEMC, Harmonising the national energy rules with the updated national energy objectives – final determination, 1 February 2024

- Reducing Scope 1 and 2 emissions by 60 per cent by 2030, compared with a base year of 2021 and net zero by 2040.
- Reducing Scope 3 emissions from Purchased Goods and Services, and Capital Goods by 48 per cent for every million dollars that we spend on these two categories by 2030, compared with a base year of 2021, and net zero by 2050.[23]

For this RIT-T assessment, we do not consider there to be any material change to greenhouse gas emissions under the proposed preferred option, as only one credible option has been identified at this stage of the RIT-T. Therefore, we have not undertaken modelling of this market benefit for this assessment as there would be no change to the outcome of the RIT-T.

[23] For more information on Transgrid's planned journey to net zero please see our website here: https://www.transgrid.com.au/about-us/our-approach/our-journey-to-net-zero

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 against the base case

The costs and benefits of each option in this document are compared against a 'do nothing' base case. Under this base case, no proactive capital investment is made to remediate the deterioration of the high voltage and secondary systems assets at Murray substation, or to address the technological obsolescence, spares unavailability, and discontinued manufacturer support for these assets. We incur regular and reactive maintenance costs, and environmental, safety and financial related risks costs, that are caused by the failure of assets at Murray substation. In addition, there would be a small avoided cost of routine operating and maintenance costs in option compared to the base case.

We note that this course of action is not expected in practice. However, this approach has been adopted since it is consistent with AER guidance on the base case for RIT-T applications.[24]

5.2 Assessment period and discount rate

The RIT-T analysis considers a 20-year assessment period from 2023/24 to 2042/43. A 20-year period takes into account the size, complexity and expected asset life of the secondary systems and provides a reasonable indication of the costs and benefits over a long outlook period.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values have been calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life. As a conservative assumption, we have effectively assumed that there are no additional cost and benefits after the analysis and period.

A real, pre-tax discount rate of 7 per cent has been adopted in all scenarios presented in this PACR, consistent with AEMO's 2023 Inputs, Assumptions and Scenarios Consultation Report (IASR).[25] 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 Central scenario results to a lower bound discount rate of 3 per cent.[26] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., AEMO's 2023 Inputs, Assumptions and Scenarios Report).[27]

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[24] Transgrid notes that the AER RIT-T Guidelines state that the base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. The AER define 'BAU activities' as ongoing, economically prudent activities that occur in the absence of a credible option being implemented. (See: AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.22).

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

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

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

5.3 Approach to estimating option costs

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

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (ie, there is an equal likelihood of over- or under-spending the estimate total).[28]

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system. In line with recent changes to the AER RIT Guidelines regarding cost estimation transparency[29], we consider this cost estimate is fit for purpose given the PACR is the earliest stage of the RIT-T process.

All cost estimates are prepared in real, 2023-24 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. In addition to that, considering available information from this substation, normal soil was considered as the basis of estimate for civil works. This means no allowance was made for rock drilling or removal. Access to the substation is deemed adequate, hence, no temporary access track was allowed for in this estimate.

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

5.4 Value of customer reliability

Consistent with the AER's RIT-T Guideline, we have developed VCR estimates that are based on the estimates developed and consulted on by the AER, weighted to reflect the mix of customers that are likely to be affected by the options.

The Murray substation predominately provides load to industrial customers in southern NSW. We have therefore applied an Industrial VCR value based on large industrial customers who have a peak demand MVA per annum of less than 10. The AER estimates 3 different industrial VCR values depending on the size of the customer and the amount of electricity the customer demands at peak times.[30] We have chosen the lowest value Industrial VCR as a conservative assumption for assessing the benefit associated with reliability risk. Since we are only assessing one credible option, the value of the VCR is not considered material to this RIT-T, i.e., it does not have any impact on the identification of the preferred option.

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[28] 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.

[29] AER, *Final amendments – Cost benefit analysis guidelines and RIT application guidelines – Explanatory statement*, October 2023, pp. 15-17.

[30] AER, *Values of customer reliability update summary – December 2022*, Appendices A - E

5.5 Three different scenarios have been modelled

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[31]

- the RIT–T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR, and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT–T instrument.

The AER's RIT-T Guidelines clarifies that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration, and that the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking or sign of the net benefit of any credible option.[32]

For the purposes of this RIT-T, we consider that the ISP scenarios are not relevant. The key input parameter that is likely to affect the ranking or sign of the net market benefits of the credible options is the probability of failure and consequence of failure of the assets at Murray substation. The probability and consequence is assessed by reference to the condition of the asset under consideration and the reliability, safety, environmental and financial consequences. These are independent from the assumptions underpinning the ISP scenarios. It follows that adopting the ISP scenarios would not be consistent with adopting scenarios that reflect parameters that could reasonably change the ranking or sign of the net market benefits of the credible options.

In line with the RIT-T Guideline, we have constructed reasonable alternative scenarios. To do this, we developed a **Central Scenario** which reflects our best estimate of each of the modelling parameters, including the asset risk (probability of failure and consequence of failure), expected unserved energy, and capital and operating costs. We developed the Central Scenario around a static model of demand scenarios, described further in our 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 sign or ranking of the credible options.

As indicated above, we consider that the key input parameter that is likely to affect the ranking or sign of the net market benefits of the credible options is the asset failure risk of the identified high voltage and secondary systems assets. We do not consider that variations in other parameters of the Central Scenario are likely to affect the outcome of the RIT-T assessment. In view of this, we have developed additional reasonable scenarios that reflect variations in the asset risk while holding other parameters the same as the Central Scenario.

Specifically, we have developed the following additional scenarios:

- A **High Risk Costs Scenario**, where the asset failure risk is 25% higher than in the Central Scenario. This higher risk would be expected to increase the frequency and duration of outages, and safety, environmental and financial risk costs, in the base case (as compared with the Central Scenario). We have modelled this scenario by increasing our estimate of gross benefits associated with avoided unserved energy and risk costs in this scenario by 25%.

[31] AER, *Regulatory investment test for transmission*, August 2020, clause 20(b).
[32] AER, *Regulatory investment test for transmission: Application guidelines*, August 2020, p.41.

- A **Low Risk Costs Scenario**, where the asset failure risk is 25% lower than in the Central Scenario. This lower failure risk would be expected to reduce the frequency and duration of outages, and safety, environmental and financial risk costs, in the base case (as compared with the Central Scenario). We have modelled this scenario by reducing our estimate of gross benefits associated with avoided unserved energy and risk costs in this scenario by 25%.

The NPV results in this PACR are reported for each scenario, as well as on a weighted basis. As we have no evidence or rationale for assigning a higher probability for one reasonable scenario over another, we have weighted each reasonable scenario equally.[33]

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

Table 55-1 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	7.0%	7.0%	7.0%
VCR ($2023-24 m)	$73.69/kWh	$73.69/kWh	$73.69/kWh
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

5.6 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 value of customer reliability;
- lower and higher assumed capital costs; and
- alternate commercial discount rate assumptions.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The results of the sensitivity tests are set out in section 6.4.

In addition, we have also sought to identify the 'boundary value' for key variables beyond which the outcome of the analysis would change.

[33] As per: AER, *Regulatory investment test for transmission: Application guidelines*, August 2020, p.50.

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 reduction in costs or risks compared to the base case.

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 6-1 NPV of gross economic benefits relative to the base case ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	1,221.34	912.90	1,529.79	1,221.34

6.2 Estimated costs

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

Table 66-2: NPV of capital costs relative to the base case ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	16.93	16.93	16.93	16.93

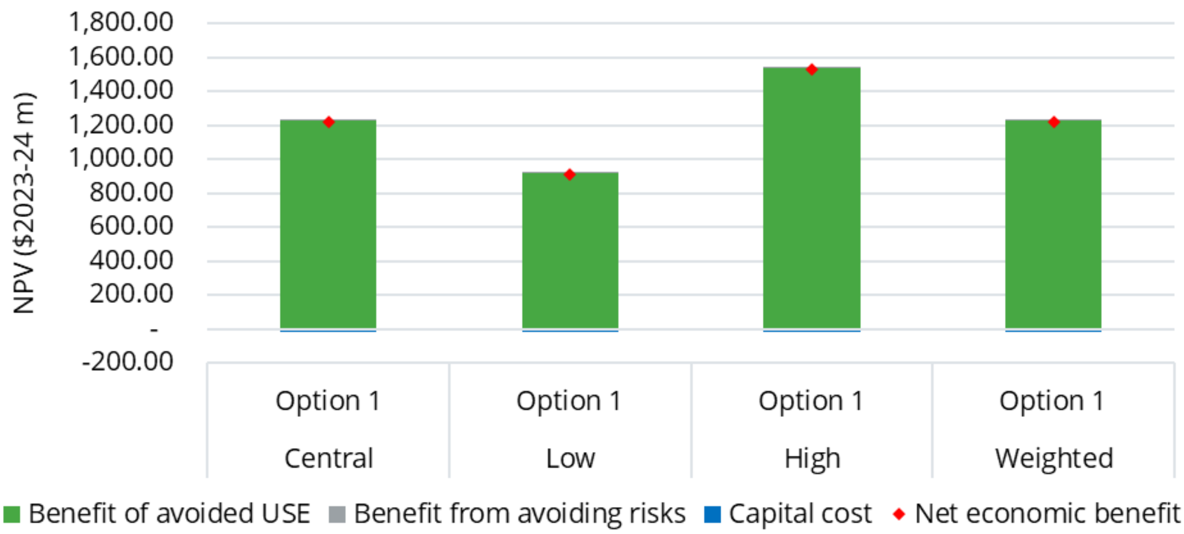
6.3 Estimated net economic benefits

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. Since we have only identified one credible option, Option 1 has the greatest net market benefits and is therefore our preferred option.

Table 66-3 NPV of net economic benefits relative to the base case ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	1,233.86	925.41	1,542.30	1,233.86

Figure 66-1 NPV of net economic benefits ($2023/24 m)



6.4 Sensitivity testing

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key modelling assumptions. The factors tested as part of the sensitivity analysis for this PACR are:

- Optimal timing of the project
- Alternate scenario weights
- Higher or lower VCRs
- Higher or lower network capital costs of the credible options
- Alternate commercial discount rate assumptions.

The sensitivity testing was undertaken as against the central scenario. Specifically, we individually varied each factor identified above and estimated the net economic benefit in that scenario relative to the base case while holding all other assumptions under the central scenario constant. The results of the sensitivity tests are set out in the sections below.

6.4.1 Optimal timing of the project

We have estimated the optimal timing for the preferred option. The optimal timing of an investment is the year when the annual benefits (avoided risk costs) from implementing the option become greater than the annualised investment costs. The analysis was undertaken under the central set of assumptions and a range of alternative assumptions for key variables. The purpose of the analysis is to examine the sensitivity of the commissioning year to changes in the underlying assumptions.

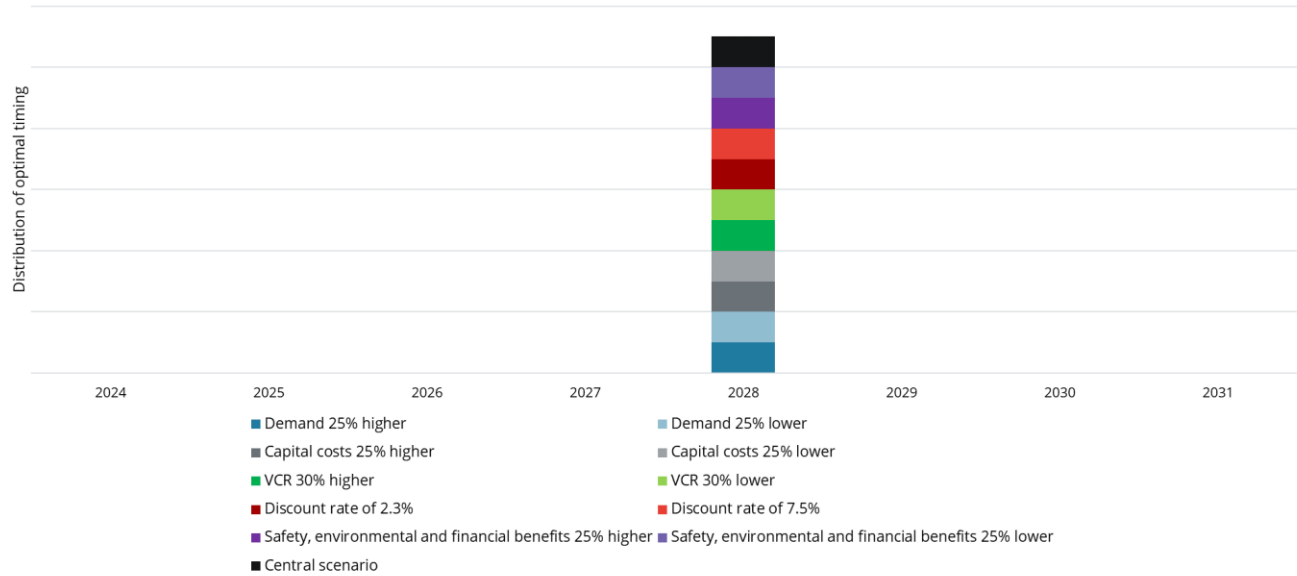
The sensitivities we considered are:

- a 25% increase / decrease in capital costs
- a 25% increase / decrease in demand
- a lower discount rate of 3% and a higher discount rate of 10.5%
- a 30% increase / decrease in the VCR
- a 25% increase / decrease in safety, environmental and financial risk costs

The results of this analysis are presented in the figure below. In all cases, the optimal timing for the preferred option is 2027/28. That is, the annual benefits from the Murray sub-station renewal is higher than the annualised investment costs.

Please note that the figure below shows the optimal year to commission the entire replacement program (as a whole). Given the scale of the investment and limitations on resources, the Murray sub-station renewal will be undertaken over a five year period ranging from 2023/24 to 2027/28.

Figure 66-2 Distribution of optimal timing under a range of different key assumptions



6.4.2 Scenario weights

As we have identified only one credible option, and since we have assessed this option to be net beneficial under all three reasonable scenarios, there are no alternative scenario weights that will change the RIT-T outcome (i.e., lead to the identification of a different preferred option, or no preferred option).

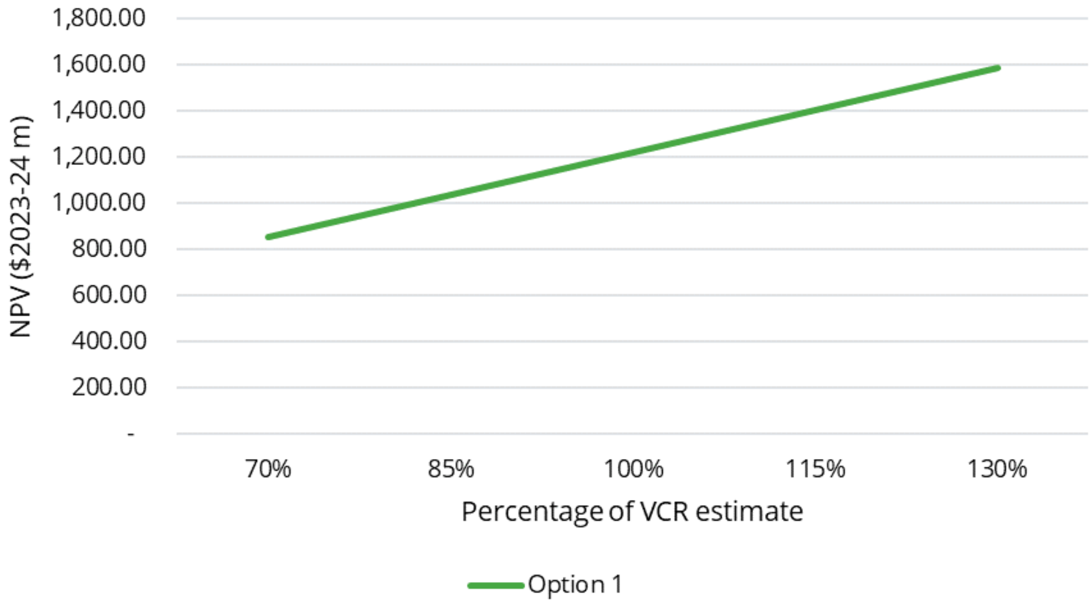
6.4.3 Value of customer reliability

We estimated the net economic benefit of each option by adopting a VCR that is 30% higher (the 'High VCR' scenario) and 30% lower (the 'Low VCR' scenario) than the estimate of VCR adopted in our central scenario. The results of this analysis are presented in the table and figure below.

Table 66-4: Sensitivity of net economic benefits under a lower and higher VCR ($2023/24 m)

Option/scenario	Low VCR	High VCR	Ranking
Sensitivity	*Central estimate - 30%*	*Central estimate + 30%*	
Option 1	852.57	1590.11	1

Figure 66-3 Sensitivity of net economic benefits under a lower and higher VCR ($2023/24 m)



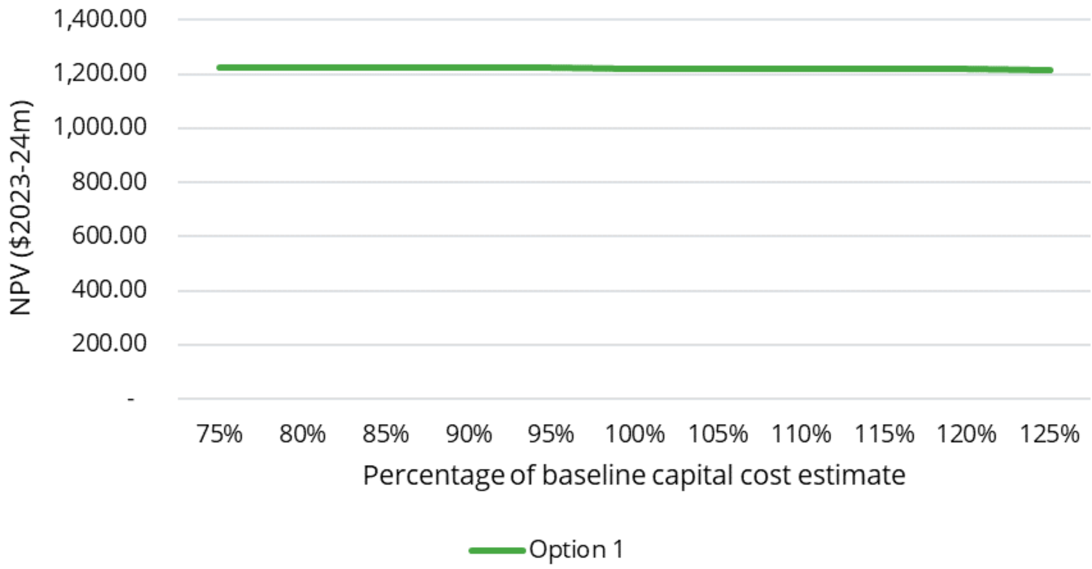
6.4.4 Network capital costs

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.

Table 66-5: Sensitivity of net economic benefits under lower and higher capital costs ($2023/24 m)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Central estimate - 25%*	*Central estimate + 25%*	
Option 1	1225.57	1217.11	1

Figure 66-4: Sensitivity of net economic benefits under lower and higher capital costs ($2023/24 m)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we considered the level of increase in the capital costs of Option 1 to change the RIT-T outcome (i.e. the base case to be the preferred option). The result of this analysis was that the capital cost would need to increase by more than 480% for the RIT-T outcome to change. Such a change in capital costs is outside the expected range of costs and, as such, this result of Option 1 being the preferred options is robust to reasonable capital cost sensitivities.

6.4.5 Discount rate

We estimated the net economic benefit of each option by adopting a low discount rate of 3% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[34] 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).[35] The results of this analysis are presented in the table and figure below.

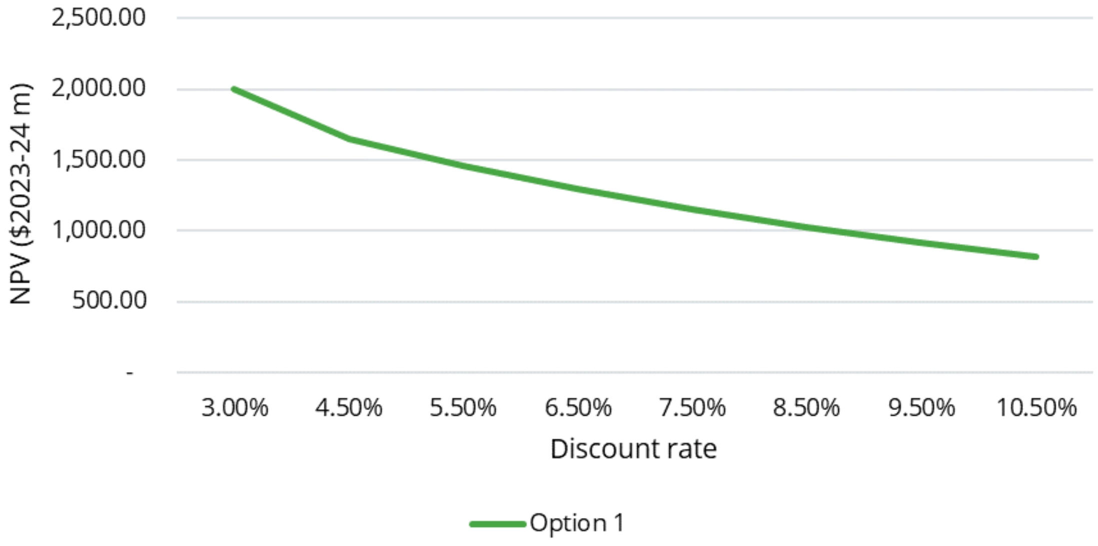
Table 66-6: Sensitivity of net economic benefits under a lower and higher discount rates ($2023/24 m)

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*3%*	*10.5%*	
Option 1	1,997.10	822.49	1

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

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

Figure 66-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2023/24



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result Option 1 not being the preferred option (i.e. the base case becoming the preferred option). Our results suggest that there is no reasonable discount rate that would change the RIT-T outcome.

7. Final conclusion on the preferred option

This PACR finds that Option 1 is the preferred option to address the identified need. Option 1 involves targeted replacement of high voltage and secondary system assets at Murray substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence.

The capital cost of this option is approximately $21.79 million (in $2023-24). The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated at approximately $0.01 million per annum (in $2023/24).

Option 1 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 or transport electricity in the market. The analysis undertaken and the identification of Option 1 as the preferred option satisfies the RIT-T.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 208.

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) See below.	See below
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	N/A
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which 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;	N/A
	(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 & 4
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 & Appendix B & C
	(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);	4
	(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;	6
	(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: (i) if estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, the reopening triggers applying to the RIT-T project.	N/A

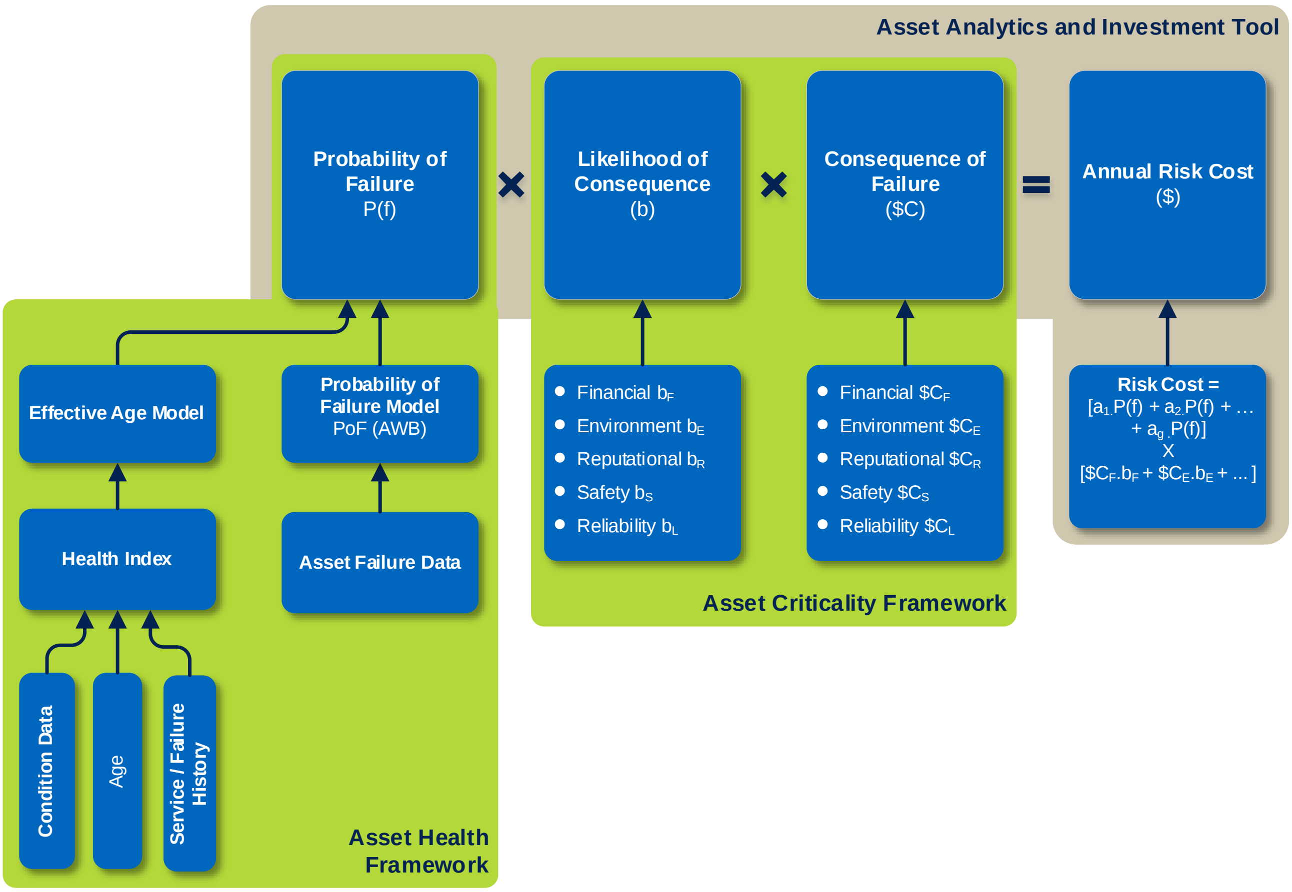
Appendix B Risk assessment framework

This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline[36] and its Principles.

A fundamental part of the risk assessment methodology is calculating the annual 'risk costs' or the monetised impacts of the reliability, safety, bushfire, environmental and financial risks.

The monetary value of risk (per year) for an individual asset failure resulting in an undesired outcome, is the likelihood (probability) of failure (in that year with respect to its age), as determined through modelling the failure behaviour of an asset (Asset Health), multiplied by the consequence (cost of the impact) of the undesired outcome occurring, as determined through the consequence analysis (Asset Criticality). Figure B-1 illustrates the base risk equation that we apply.

Figure B-1 Risk cost calculation



Economic justification of Repex to address an identified need is supported by risk monetised benefit streams, to allow the costs of the project or program to be assessed against the value of the avoided risks and costs. The major quantified risks we apply for Repex justifications include asset failures that materialise as:

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

- 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 C 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,[37] 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.
- The future health of an asset (health forecasting) is a function of its current health and any factors causing accelerated (or decelerated) degradation or 'age shifting' of one or more of its components. Such moderating factors can represent the cumulative effects arising from continual or discrete exposure to unusual internal, external stresses, overloads and faults.
- 'Future effective age' is derived by moderating 'current effective age' based on factors such as, external environment/influence, expected stress events and operating/loading condition.

The 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.

Asset	Weibull parameters	
	η	β
Power Transformer	54.21	3.61
Circuit Breakers (11kV Switchboard)	47.76	4.3
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

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

PC	12.7	2.09
Meter - Microprocessor	15.5	1.74
DC Battery	16.5	1.49
DC Charger	19.8	1.24