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Managing the risk of circuit breaker failure

RIT-T Project Assessment Conclusions Report

Issue date: 19 December 2023

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for managing the risk of circuit breaker failure on the New South Wales (NSW) transmission network. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Circuit breakers are essential for the control and protection of the high voltage network. We have identified 122 circuit breakers on our network that will have reached or be approaching the end of their technical life by 2027/28. The probability of failure for these assets is high and is expected to increase as the assets age. If left unaddressed, this will result in greater unserved energy for consumers, greater safety and environment risk, and greater financial costs associated with emergency repair and replacements.

We consider it prudent and cost effective to manage this risk of circuit breaker failure through an asset replacement program during the 2023/24 and 2027/28 regulatory period.

Identified need: ensure the safe and reliable operation of our transmission network by managing the risk of circuit breaker failure

The identified need for this project is to ensure the safe and reliable operation of our transmission network by addressing the risk of failure of certain circuit breakers that are approaching the end of their technical life.

The end-of-life assets have been identified through the application of our Network Asset Health Framework to the circuit breaker population to determine each assets effective age and identify assets with increased risk of failure. The evaluated health index inputs for circuit breakers considers aging factors including natural age, operation count and high wear switching applications; as well as performance factors including defects rate and cost, condition monitoring results and sub population type issues.

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 have identified 122 circuit breakers that will have reached or be approaching the end of their technical life by 2027/28. These are all live head circuit breakers (LHCBs) and therefore have separate current transformers installed within the switch bay.

The associated current transformers for 55 of the 122 identified circuit breakers are also approaching the end of their technical life. It is therefore feasible to replace the two units with a single dead tank circuit breaker (DTCB) which incorporates both the circuit breaker and current transformers.

Installing a DTCB removes the need for a separate current transformer and therefore provides additional benefits through avoiding the risk of in-service current transformer failure which can result in interruptions to customer load, safety and environmental consequences and emergency repair and replacement costs.

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. Given the quantity of circuit breakers that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program. This replacement will help limit the amount of in-service failures that occur (along with the associated interruptions to customer load, and safety and environmental consequences).

No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 18 May 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. The following changes have occurred since the PSCR which have not made an impact on the preferred option:

- Updated the discount rate used
- Updated the VCR

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

We note that, since the PSCR was released, there has been a law change to introduce an emissions reduction objective into the national energy objectives[1] and that the National Electricity Rules are currently being updated to add a new category of market benefit to the RIT-T reflecting changes in Australia's greenhouse gas emissions.[2] As part of the transitional arrangement of the rule we are not required to consider emissions reduction as part of this PACR. However, we have been proactive in considering these impacts are already implementing a trial of new low greenhouse gas (GHG) insulation technologies and will evaluate wider adoption after its completion.

Credible options considered

We identified two credible network options that would meet the identified need from a technical, commercial, and project delivery perspective[3]. These options are summarised in Table E-1.

Table E-1 Summary of credible options, $2021/22

Category	Number of existing CBs in this category	Option 1	Option 2
LHCBs that are reaching the end of their technical life, and for which (i) the associated current transformers are also reaching end of life, and (ii) replacement with a DTCB is technically feasible	55	Replace the existing LHCB with a new LHCB	Replace the existing LHCB and CT with a DTCB

1 On 12 August 2022, Energy Ministers agreed to fast track the introduction of an emissions reduction objective into the national energy objectives, consisting of the National Electricity Objective (NEO), National Gas Objective and National Energy Retail Objective. On 21 September 2023, the *Statutes Amendment (National Energy Laws) (Emissions Reductions Objectives) Act 2023* (the Act) received Royal Assent.

2 AEMC, *Harmonising the electricity network planning and investment rules and AER guidelines with the updated energy objectives (electricity)*, draft determination, 26 October 2023, p. i.

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

Category	Number of existing CBs in this category	Option 1	Option 2
LHCBs that are reaching the end of their technical life, and for which, (i) a DTCB is not technically feasible, (ii) there are no associated current transformers, or (iii) the current transformers have a substantial remaining life	67	Replace the existing LHCB with a new LHCB	Replace the existing LHCB with a new LHCB
Estimated capex ($2021-22)		32.27	41.50
Expected commission date		2028	2028

Appendix B presents a list of circuit breakers identified by this need and the proposed replacement approach under the preferred option, Option 2.

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

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T. The objective of this identified need is to avoid the increasing risks of asset failure due to the deteriorated condition of the circuit breakers. For non-network options to assist, they would need to provide greater net economic benefits than the network options. That is, non-network options would need to reduce the reliability, safety and financial risk related costs (which in practice are not expected to be affected by non-network solutions due to the nature of circuit breakers). We did not receive any submissions from proponents of these solutions in response to the PSCR.

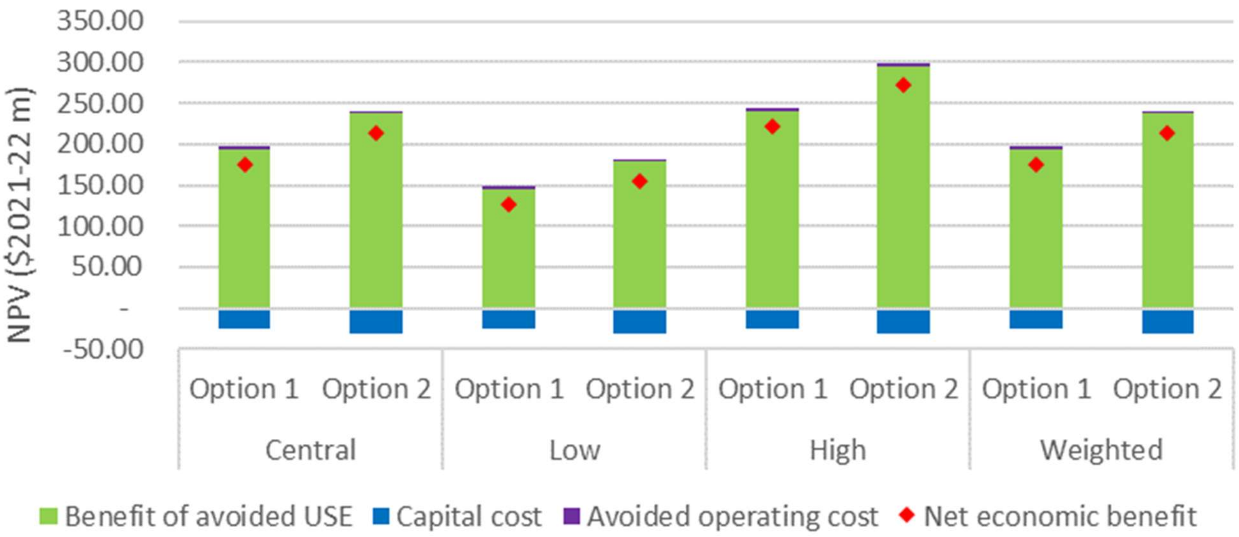
Conclusion: Replacing 55 of the identified assets with dead tank circuit breakers and the remaining 67 with live head circuit breakers is optimal

This PACR finds that implementation of Option 2 is the preferred option at this final stage of the RIT-T process. Under Option 2:

- 55 of the 122 identified circuit breakers will be replaced with a DTCB. For these circuit breakers, the associated current transformers are approaching the end of their technical life.
- 67 of the 122 identified circuit breakers will be replaced with a LHCB. For these circuit breakers, either replacement with a DTCB is not technically feasible, there is no associated current transformers, or the current transformers have substantial remaining life.

We have assessed that Option 2 is net beneficial under all three reasonable scenarios considered in this PACR. On a weighted basis, where each scenario is weighted equally, Option 2 is expected to deliver net benefits of approximately $217.10m.

Figure E-1 Net economic benefits ($m, PV)



The capital cost of this option is approximately $41.50 million (in $2021/22). 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 $0.16 million per annum (in $2021/22).[4] All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

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 May 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:
  - 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.

4 Average operating costs over the period 2028/29 to 2049/50.

Parties wishing to raise a dispute notice with the AER may do so prior to 23 January 2024[5] (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 'Circuit breaker renewal program PACR'.

[5] Additional days have been added to cover public holidays

Contents

1. Introduction

This Project Assessment Conclusions Report (PACR) represents the final step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for managing the risk of circuit breaker failure on the NSW transmission network.

Circuit breakers are essential for the control and protection of the high voltage network. We have identified 122 circuit breakers on our network that will have reached or be approaching the end of their technical life by 2027/28. The probability of failure for these assets is high and is expected to increase as the assets age. If left unaddressed, this will result in greater unserved energy for consumers, greater safety and environment risk, and greater financial costs associated with emergency repair and replacements.

We consider it prudent and cost effective to manage this risk of circuit breaker failure through an asset replacement program during the 2023/24 and 2027/28 regulatory period.

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 and there have been no material developments

We published a Project Specification Consultation Report (PSCR) on 18 May 2023 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

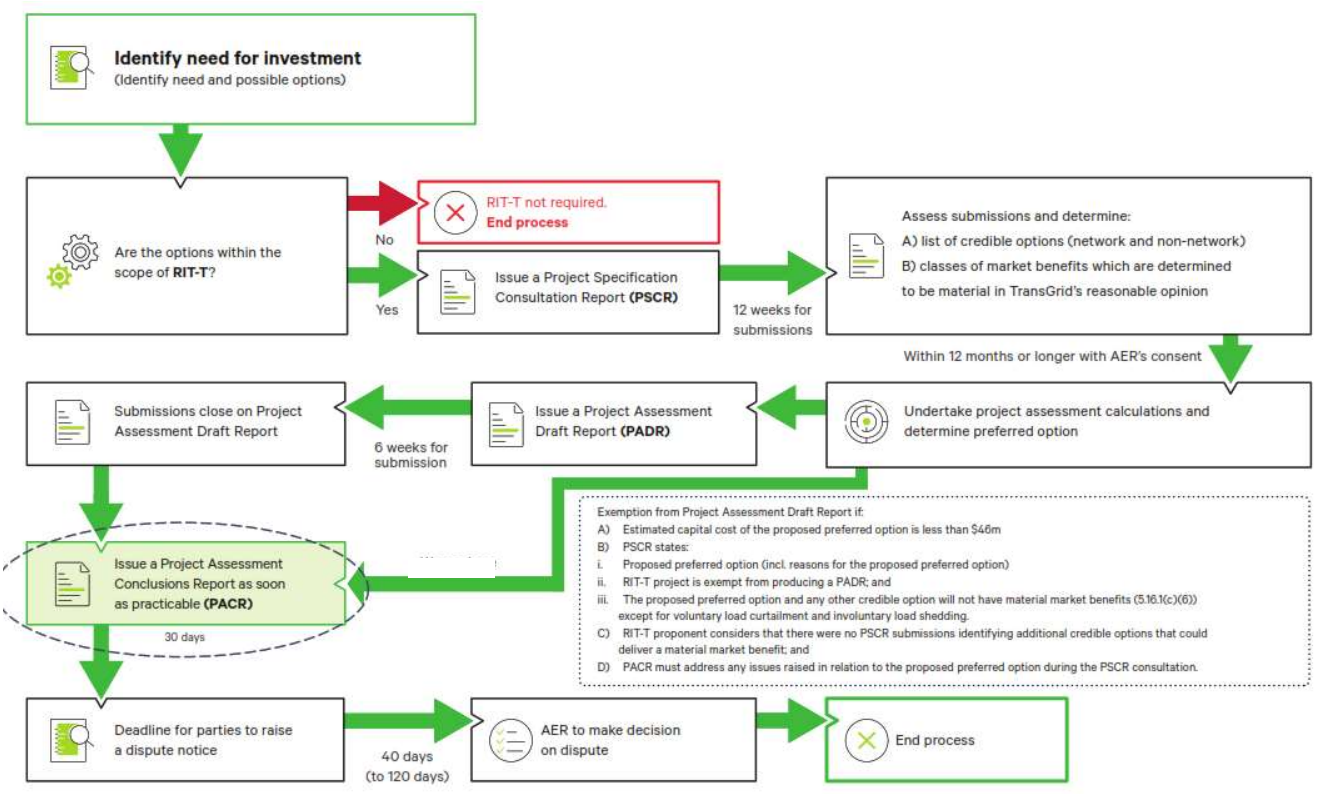
In addition, no additional credible options were identified during the consultation period following publication of the PSCR. No other material changes have occurred since the PSCR that have made an impact on the preferred option.

1.3. Next steps

As outlined in Figure 1-1 below, 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 May 2023. No submissions were received in response to the PSCR.

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

Figure 1-1 This PACR is the final stage of the RIT-T process[7]



Parties wishing to raise a dispute notice with the AER may do so prior to 23 January 2024[8] (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 'Circuit breaker renewal program PACR'.

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

[8] Additional days have been added to cover public holidays

2. The identified need

2.1. Background to the identified need

Circuit breakers are essential for the control and protection of the high voltage network. Circuit breakers are electrical switches that operate automatically to interrupt the abnormal flow of electricity during network faults. Their operation ensures network stability, protects people from injury and minimises damage of electrical equipment under fault conditions. Circuit breakers are also used to energise and de-energise transmission lines and other electrical assets to enable maintenance and capital works.

Circuit breakers can be categorised by their external design into live head circuit breakers (LHCBs) and dead tank circuit breakers (DTCBs). In a LHCB, the vessel containing the interrupter (isolating switch) is at a potential above the ground. When a LHCB is used, separate current transformers must be installed. Current transformers reduce transmission system currents (1000-10,000A) to a range (up to 2A) that is suitable for secondary systems equipment. In a DTCB, the vessel containing the interrupter is at ground potential. External bushings are used for incoming and outgoing high voltage connections which then permit the installation of current transformers on them.

We have a range of LHCB and DTCBs operating from 11kV up to 500kV, with various ages and technologies. The circuit breakers are located throughout the network with a wide range of duty cycles, environmental exposure and loading.

2.2. Description of the identified need

The identified need for this project is to ensure the safe and reliable operation of our transmission network by addressing the risk of failure of certain circuit breakers that are approaching the end of their technical life.

We have identified 122 circuit breakers on our network that will have reached or be approaching the end of their technical life by 2027/28. All of these circuit breakers are LHCBs and therefore have current transformers that are installed separate to the circuit breaker in the switch bay. For 55 of the 122 identified circuit breakers, the associated current transformers will also have reached or be approaching the end of their technical life by 2027/28. A list of the end-of-life circuit breakers is provided in Appendix B.

The end-of-life assets have been identified through the application of our Network Asset Health Framework to the circuit breaker population to determine each assets effective age and identify assets with increased risk of failure. The evaluated health index inputs for circuit breakers considers aging factors including natural age, operation count and high wear switching applications; as well as performance factors including defects rate and cost, condition monitoring results and sub population type issues.

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 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. Given the high population of circuit breakers that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program. This replacement will help limit the amount of in-service failures that occur (along with the associated interruptions to customer load, and safety and environmental consequences).

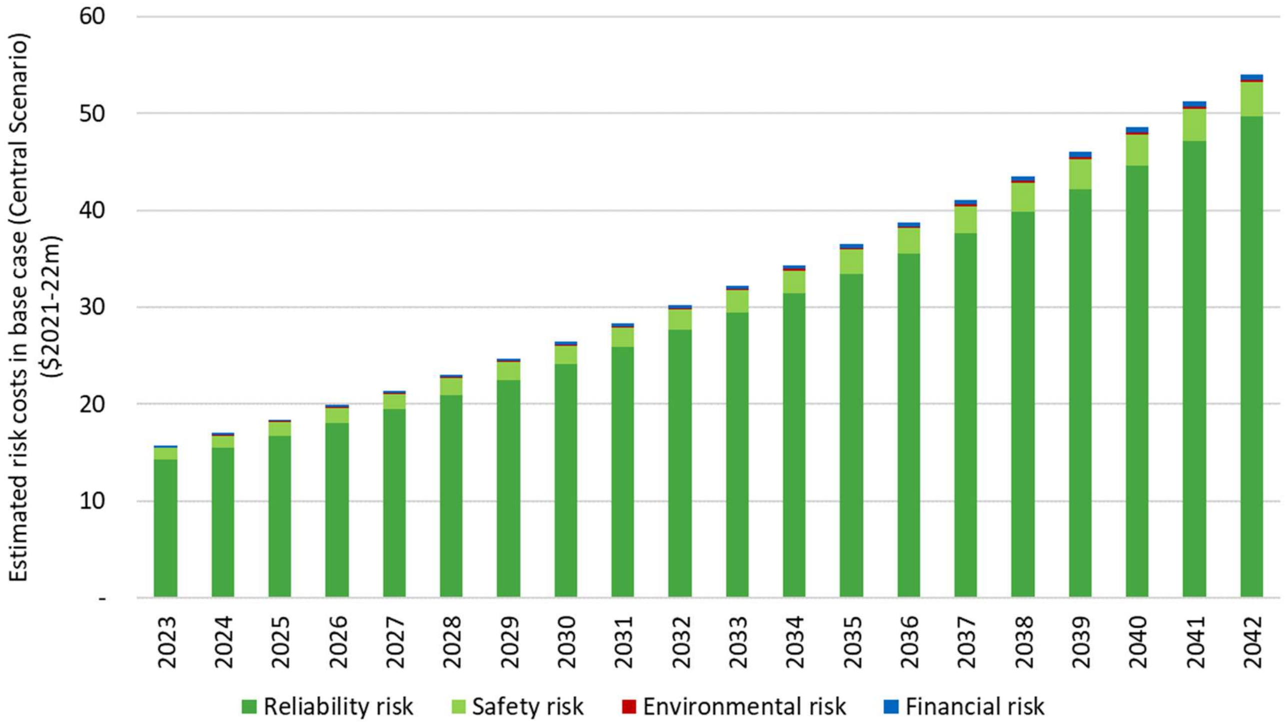
2.3. Assumptions underpinning the identified need

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

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

Figure 2-1 summarises the increasing risk costs over the assessment period under the base case.

Figure 2-1 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 $16 million in 2022/23, and it is expected to increase going forward if action is not taken (reaching approximately $27 million by 2030 and $55 million by the end of the 20-year assessment period).

2.3.1. Asset health and the probability of failure

2.3.1.1. Age factors

- **Natural age:** A circuit breakers natural age is calculated from its first installed date. Circuit breakers typically have an asset life of 40 years.
- **Operation count:** Circuit breaker operating statistics for the past 3 years are obtained from SCADA to calculate the average number of operations (usage rate) per year. This is used to forecast the number of operations for each circuit breaker in future years. The threshold value in terms of total number of operations is set to 7,000 operations. This figure represents the operations-based life expectancy of a circuit breaker and is based on various factors including operation count limits specified by the manufacturer, mechanical endurance testing, variability in production line quality, and our own experience in asset performance.
- **Reactive switching:** The type of switching duties are categorised into reactive and non-reactive switching. Circuit breakers performing reactive switching have increased contact wear rates and reduced switching service life. The reactive switching factor is also scaled by the operating duty and so will affect the effective age score progressively with operation numbers. This approach to shortened operating life expectancy for reactive switching is consistent with manufacturer recommendations.

2.3.1.2. Performance factors

- **Defect Count:** Defect counts provides an indication of historical issues. The total number of recorded defect instances are identified against each asset from defect work orders. Assets with high statistical defect count are considered to have an increased risk of presenting future defects with increased risk of a defect resulting in a life ending scenario.
- **Defect Cost:** Defect cost provides an indication of past issue severity. The sum of all recorded actual defect costs is identified against each asset from defect work orders. Assets with high statistical defect cost are considered to have an increased risk of presenting high cost and severe future defects with increased risk of a defect resulting in a life ending scenario.
- **Condition Monitoring Results:** Condition monitoring results provide an indication of asset condition. Historical condition monitoring result data is obtained through maintenance activities and diagnostic testing. Test parameters include open and close timing, contact resistance and insulation quality with only the latest test result for each parameter evaluated. Assets with high statistical condition monitoring result exceptions are considered have an increased risk of presenting operationally urgent defects with increased risk of resulting in a life ending scenario.
- **Type Issues:** Type issues are identified with historical circuit breaker designs and technologies where there is an inherent vulnerability in the design, frequent and severe failures are observed, manufacturer has withdrawn technical and parts support. A type issue is identified where factors credibly impact on the expected service life of circuit breaker sub population which increases the risk of a defect resulting in a life ending failure.

2.3.2. Reliability risk

We have considered the risk of unserved energy for customers following a failure of the circuit breakers identified in this PACR. The likelihood of a consequence considers the likelihood of contingent planned/unplanned outages, 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.

Reliability risk makes up 91.5 per cent of the total estimated risk cost in present value terms.

2.3.3. Safety risk

This refers to the safety consequence to staff, contractors and/or members of the public of an asset failure. The likelihood of a consequence considers the 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. 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 6.9 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 0.5 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 considers any compliance and regulatory factors which are not covered by the other categories. The monetary value takes into account the associated cost with disruption to business operations, third party liabilities, and the cost of replacement or repair of the asset, including any temporary measures.

Financial risk makes up 1.1 per cent of the total estimated risk cost in present value terms.

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.

As indicated above, we have identified 122 circuit breakers on our network that will have reached or be approaching the end of their technical life by 2027/28 (Appendix B).

- For 55 of the 122 identified circuit breakers, the associated current transformers will also reach the end of their technical life by 2027/28. For these circuit breakers, we consider that there are two technically and commercially feasible options, which are to replace the existing LHCB with a new LHCB, or to replace the existing LHCB and associated current transformer with a DTCB.
- For 67 of the 122 identified circuit breakers, either replacement with a DTCB is not technically feasible, there are no associated current transformers, or the current transformers have substantial remaining life. For these circuit breakers, we consider that replacing the existing LHCB with a new LHCB is the only technically and commercially feasible option.

On this basis, we consider that there are two credible network options that can meet the identified need. These options are summarised in Appendix B. We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T.

All costs and benefits presented in this PACR are in 2021/22 dollars, unless otherwise stated.

Table 3-1 Summary of credible options

Category	Number of existing CBs in this category	Option 1	Option 2
LHCBs that are approaching the end of their technical life, and for which (i) the associated current transformers are also approaching end of life, and (ii) replacement with a DTCB is technically feasible	55	Replace the existing LHCB with a new LHCB	Replace the existing LHCB and CT with a DTCB
LHCBs that are approaching the end of their technical life, and for which, (i) a DTCB is not technically feasible, (ii) there is no associated current transformers, or (iii) the current transformers have a substantial remaining life	67	Replace the existing LHCB with a new LHCB	Replace the existing LHCB with a new LHCB
Estimated capex ($2021-22m)		32.27	41.50
Expected commission date		2028	2028

3.1. Base case

The costs and benefits of each option in this PACR are compared against those of a base case.[9] Under this base case, no proactive capital investment is made to replace existing LHCBs that are reaching end of life. These assets will continue to be maintained under the current regime and will operate until they fail. The annual routine operating and maintenance cost is forecast to rise from $448,581 in 2022-23 to $731,343 in 2041-42.

The degraded condition of the 122 circuit breakers that have been identified for replacement under this program will lead to an increase in unplanned outages as the assets continue to deteriorate and age. Their failure will also impact primary assets, such as lines and transformers, as they will be out of service for longer periods. This is expected to result in unserved energy of approximately 309MWh in 2022-23 and 639MWh in 2032-33. It will also lead to higher safety, environmental, and financial risk costs, that are caused by the failure of circuit breakers to operate when required.

The aggregate risk cost under the base case is currently estimated at around $16 million in 2022/23, and it is expected to increase going forward if action is not taken (reaching approximately $26 million by 2030 and $54 million by the end of the 20-year assessment period).

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.

The tables below provide a breakdown of the expected operating expenditure under the base case for the first year, as well as operating expenditure under the base case from FY23 to FY42 by five-year increments.

Table 3-2 Capital and Operating expenditure under the base case from FY23 to FY42 ($2021-22)

	Capital Expenditure	Operating Expenditure
2023	-	$448,581
2024	-	$448,581
2025	-	$448,581
2026	-	$448,581
2027	-	$502,912
2028	-	$502,912
2029	-	$502,912
2030	-	$502,912
2031	-	$502,912
2032	-	$574,851
2033	-	$574,851

9 Transgrid notes that the August 2020 AER RIT-T Guidelines (p. 21) 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.

2034	-	$574,851
2035	-	$574,851
2036	-	$574,851
2037	-	$651,057
2038	-	$651,057
2039	-	$651,057
2040	-	$651,057
2041	-	$651,057
2042	-	$731,343
Total	-	**$11,169,767**

3.2. Option 1 – Replace with new LHCBs

Under Option 1, all 122 circuit breakers identified in this RIT-T that will reach the end of their technical life by 2027/28, will be replaced with new LHCBs. This option is based on a like-for-like approach, whereby the existing LHCBs are replaced by modern equivalent assets. Any associated current transformers will continue to be maintained and operated under the current regime as with the base case.

The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. The capital cost of this option is approximately $32.27 million (in $2021-22). This capital cost is comprised of $12.44 million in labour costs, $14.53 million in materials costs, and $5.30 million in expenses. Table 3-3 below provides an annual breakdown of the estimated capital cost. The annual routine operating and maintenance cost is forecast to decrease to $106,458 in 2028-29 under this option, increasing to $172,567 in 2041-42.

We expect that the LHCBs and current transformers will have an asset life of 40 years.

Table 3-3 Option 1 Capital and Operating expenditure ($2021-22)

	Capital Expenditure ($m)	Operating Expenditure
2023	-	$448,581
2024	$6.455	$448,581
2025	$6.455	$448,581
2026	$6.455	$448,581
2027	$6.455	$315,433
2028	$6.455	$315,433
2029	-	$315,433
2030	-	$315,433
2031	-	$315,433
2032	-	$114,942
2033	-	$114,942

2034	-	$114,942
2035	-	$114,942
2036	-	$114,942
2037	-	$139,179
2038	-	$139,179
2039	-	$139,179
2040	-	$139,179
2041	-	$139,179
2042	-	$172,567
Total	**$32.275**	**$4,814,661**

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

Following the implementation of Option 1, the costs associated with reliability, safety, environmental and financial risks are significantly reduced. A reduction in the rate of failure of the relevant circuit breakers will reduce expected unserved energy and the costs of emergency repair and replacements. A reduction in the risk of explosive failure will reduce the risk of injury to nearby people and infrastructure.

Transgrid has estimated that total risk costs under Option 1 will be approximately $4.83m in 2028/29, after all identified circuit breakers have been replaced (in $2021-22).

3.3. Option 2 – Replace with DTCB if technically and commercially viable

Under Option 2, 55 of the 122 identified circuit breakers will be replaced with a DTCB. For these circuit breakers, the associated current transformers are approaching the end of their technical life. The remaining 67 of the 122 identified circuit breakers will be replaced with a LHCB. For these circuit breakers, either replacement with a DTCB is not technically feasible, there is no associated current transformers, or the current transformers have substantial remaining life.

The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. The capital cost of this option is approximately $41.50 million (in $2021-22). This capital cost is comprised of $15.48 million in labour costs, $20.0 million in materials costs, and $6.07 million in expenses.

The table below provides a breakdown of the estimated capital cost. The annual routine operating and maintenance cost is forecast to decrease to $106,458 in 2028-29 under this option, increasing to $172,567 in 2041-42.

We expect that the DTCBs and LHCBs will have an asset life of 40 years.

Table 3-4 Option 2 Capital and Operating expenditure ($2021-22)

	Capital Expenditure ($m)	Operating Expenditure
2023	-	$448,581
2024	$8.300	$448,581
2025	$8.300	$448,581
2026	$8.300	$448,581
2027	$8.300	$315,433
2028	$8.300	$315,433
2029	-	$315,433
2030	-	$315,433
2031	-	$315,433
2032	-	$114,942
2033	-	$114,942
2034	-	$114,942
2035	-	$114,942
2036	-	$114,942
2037	-	$139,179
2038	-	$139,179
2039	-	$139,179
2040	-	$139,179
2041	-	$139,179
2042	-	$172,567
Total	**$41.500**	**$4,814,661**

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

Following the implementation of Option 2, the costs associated with reliability, safety, environmental and financial risks are significantly reduced. A reduction in the rate of failure of the relevant circuit breakers and removal of failure risk for relevant associated current transformers will reduce expected unserved energy and the costs of emergency repair and replacements. A reduction in the risk of explosive failure will reduce the risk of injury to nearby people and infrastructure.

Transgrid has estimated that total risk costs under Option 2 is negligible in 2028/29, after all identified circuit breakers have been replaced (in $2021-22). The difference with Option 2 is primarily due to the lower combined asset failure risk of DTCBs compared to separate LHCBs and CTs.

3.4. 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 3-5.

Table 3-6 Options considered but not progressed

Option	Reason(s) for not progressing
Proactive replacement of CTs in Option 1	The scope of work is similar to Option 1, except that the 55 current transformers that are approaching the end of their technical life are replaced on a proactive basis. We do not consider this option to be commercially feasible as we expect that proactively replacing the 55 CTs life-for-like will offer lower net benefits (i.e. high cost and lower benefit) than Option 2, given that these CTs are already approaching or at end of life, and installation of a DTCB removes separate CTs from the network, hence eliminating associated asset failure risks and efficient implementation of DTCB can only be achieved at the same time as replacing the CB.
Refurbishment and overhaul	This scope of work involves refurbishing all deteriorating components of a circuit breaker that is typically greater than 30 years old. We do not consider this to be a technically or commercially feasible option because: • The cost of such refurbishment is substantial, while the potential life extension from the overhaul is expected to be no more than 10 years. • The overhaul is expected to result in higher defect and failure rates than the options considered due to the retention of outdated and suboptimal component design. • Parts and technician support is expected to be limited or unavailable, greatly extending the time needed to address the identified need.
Increased maintenance or inspections	The condition issues have already been identified and cannot be rectified through increased maintenance or inspections. This option has not been progressed as it is not technically capable of addressing the identified need.
Elimination of all associated risk	This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.

3.5. No material inter-network impact is expected

We have considered whether the credible option listed above is expected to have material inter-regional impact.[10] 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."*

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

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:[11]

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We note that Option 2 satisfies these conditions as it does not modify any aspect of electrical or transmission assets. By reference to AEMO's screening criteria, there are no material inter-network impacts associated with Option 2.

[11] 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

4. Materiality of market benefits

This section outlines the classes of market benefits prescribed in the National Electricity Rules (NER) and whether they are considered material for this RIT-T.[12]

Many of the expected benefits associated with the credible options are captured in the expected costs avoided by the options (i.e., the avoided expected costs compared to the base case). These include avoided costs associated with routine maintenance and avoided risk costs. Of these avoided costs, only unserved energy through involuntary load shedding is considered a market benefit class under the NER, as discussed further below.

We note that, since the PSCR was released, there has been a law change to introduce an emissions reduction objective into the national energy objectives[13] and that the National Electricity Rules are currently being updated to add a new category of market benefit to the RIT-T reflecting changes in Australia's greenhouse gas emissions.[14] As part of the transitional arrangement of the rule we are not required to consider emissions reduction as part of this PACR. However, we have been proactive in considering these impacts are already implementing a trial of new low greenhouse gas (GHG) insulation technologies and will evaluate wider adoption after its completion.

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 RIT-T assessment. In the base case, involuntary load shedding would be expected to occur following a failure of circuit breakers on our network. The probability of asset failure is expected to increase over time as the condition of the assets continue to deteriorate.

We have estimated expected load shedding under the base case and each option. These forecasts are based on probabilistic planning studies of failure rates and repair times. 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 each option.

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.[15]

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[12] The NER requires that all classes of market benefits identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or classes) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.15A.2(5). See Appendix A for requirements applicable to this document.

[13] On 12 August 2022, Energy Ministers agreed to fast track the introduction of an emissions reduction objective into the national energy objectives, consisting of the National Electricity Objective (NEO), National Gas Objective and National Energy Retail Objective. On 21 September 2023, the *Statutes Amendment (National Energy Laws) (Emissions Reductions Objectives) Act 2023* (the Act) received Royal Assent.

[14] AEMC, *Harmonising the electricity network planning and investment rules and AER guidelines with the updated energy objectives (electricity)*, draft determination, 26 October 2023, p. i.

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

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

4.3. No other classes of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(4) requires that we consider the following classes of market benefits, listed in Table 4-1, arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons in Table 4-1.

Table 4-1 Reasons non-wholesale electricity market benefits are considered immaterial

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.[16] 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.[17] We do not consider there to be any option value with the options considered in this PSCR. 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.

16 AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p.53-54.
17 AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p.53-54.

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 investment is undertaken to replace existing circuit breakers which are run until they fail.

The deteriorating condition of the 122 circuit breakers that have been identified for replacement under this RIT-T will lead to an increase in unplanned outages as the assets continue to deteriorate and age. Their failure will also impact primary assets, such as lines and transformers, as they will be out of service for longer periods. It will also lead to higher safety, environmental and financial related risk costs that are caused by the failure of circuit breakers to operate when required. In addition, there would be higher routine operating and maintenance costs in the base case compared to the options developed.

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.[18]

5.2. Assessment period and discount rate

The RIT-T analysis considers a 20-year assessment period from 2022/23 to 2041/42. A 20-year period takes into account the size, complexity and expected asset life of the circuit breakers 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 as the central assumption for the NPV analysis presented in this PACR, consistent with AEMO's Inputs Assumptions and Scenarios Consultation Report[19] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[20] 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

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

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

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

bound discount rate of 3 per cent.[21] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[22]

5.3. Approach to estimating option costs

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

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).[23]

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

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

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

5.4. Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER[24]. The options considered involve the replacement of capacitor banks across our network. As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options.

5.5. 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 market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to

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21 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

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

23 For further detail on our cost estimating approach refer to section 6 of our Repex Overview Paper submitted with our 2023-28 Revenue Proposal.

24 AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124.

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

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

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

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) will be investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).[25],[26],[27]

Table 5-1 Summary of scenarios

Variable / Scenario	Central scenario	Low risk costs scenario	High risk costs scenario
Scenario weighting	33%	33%	33%
Discount rate	7%	7%	7%
VCR ($2022-23)	$49,216/MWh	$49,216/MWh	$49,216/MWh
Network capital costs	Base estimate	Base estimate	Base estimate
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

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

25 AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, pp. 40-41.
26 We consider the approach to scenarios and sensitivities to be consistent with the AER guidance provided in November 2022 in the context of the disputes of the North West Slopes and Bathurst, Orange and Parkes RIT-Ts. See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 18-20 & 31-32, as well as with the AER's RIT-T Guidelines.
27 AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123-124

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.

6. Assessment of credible options

This section outlines the assessment we have undertaken of the credible network options. The assessment compares the costs and benefits of each credible 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 2021/22 dollars.

6.1. Estimated gross benefits

below summarises the present value of the gross benefits for each credible option, relative to the base case, under the three scenarios. The benefits included in the assessment are:

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

Table 6-1 Estimated gross benefits from credible options relative to the base case ($2021/22m)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	193.48	145.96	241.00	193.48
Option 2	237.30	178.83	295.78	237.30

The results show that under all three scenarios, the estimated benefits are higher for Option 2 than Option 1 (in NPV terms). On a weighted basis, the estimated gross benefit for Option 2 is approximately $237m, which is $44m or 23% higher than Option 1 ($2021/22m).

6.2. Estimated costs

Table 6-2 below summarises the estimated capital costs of each credible option, relative to the base case, in present value terms. The results have been presented separately for each reasonable scenario, and on a weighted basis.

Table 6-2 Costs of credible options relative to the base case ($2021/22m)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	24.73	24.73	24.73	24.73
Option 2	31.81	31.81	31.81	31.81

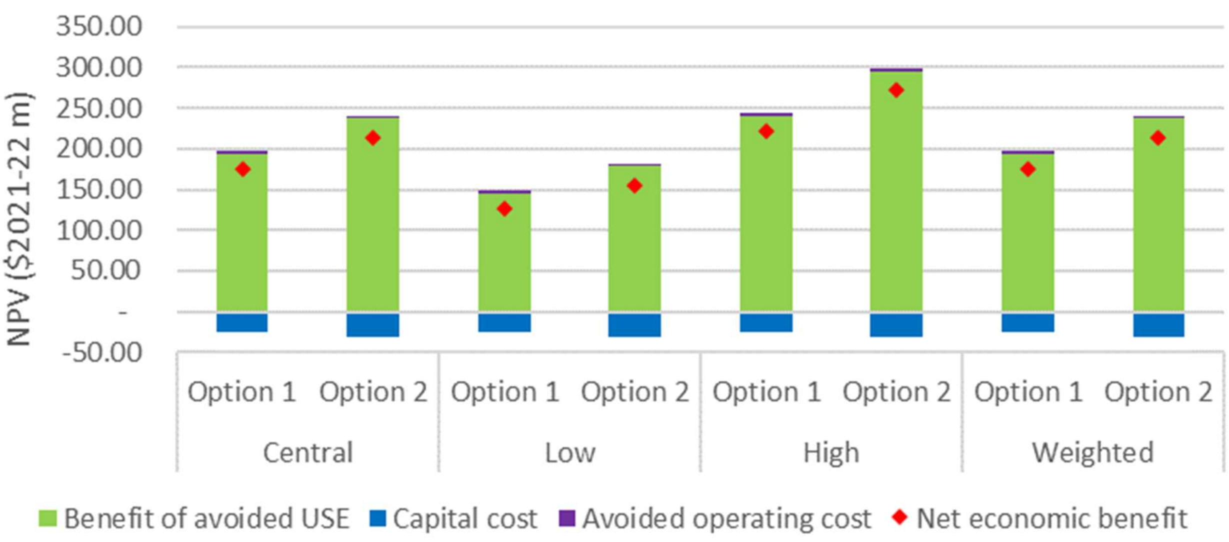
6.3. Estimated net economic benefits

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 relative to the base case. The results have been presented separately for each reasonable scenario, and on a weighted basis. The table also shows a ranking of the options, where options with a higher net economic benefit under the weighted scenario are accorded a higher rank.

Table 6-3 Net economic benefits for Option 1 relative to the base case ($m, PV)

Option	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	174.99	127.47	222.51	174.99
Option 2	213.53	155.05	272.01	213.53

Figure 6-1 Net economic benefits ($2021/22m)



Overall, the results show that Option 2 is ranked higher than Option 1 in every scenario.

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.

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

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.

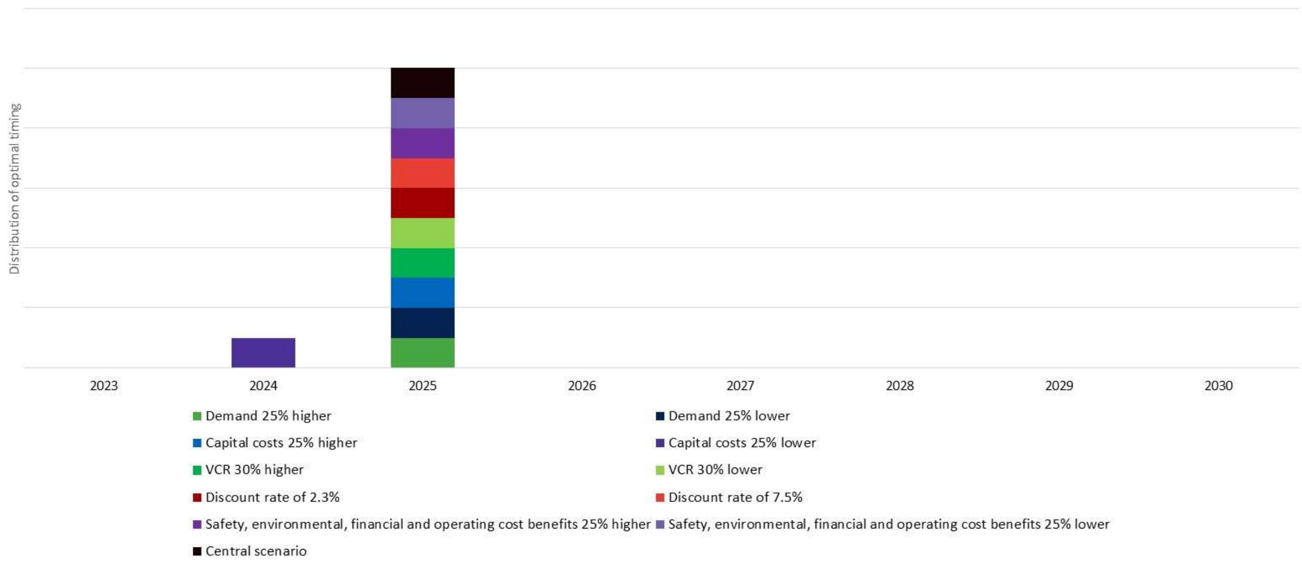
The sensitivities we considered are:

- 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 most cases, the optimal timing for the preferred option is 2024/25. In the case where capital costs are assumed to be low (75% of the central estimate), the optimal timing for the preferred option is brought earlier by one year to 2023/24.

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 replacement of individual circuit breakers will be undertaken over a five-year period ranging from 2023/24 to 2027/28.

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



6.4.2. Scenario weights

We have estimated that Option 2 is preferred under all three reasonable scenarios. As such, there is 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).

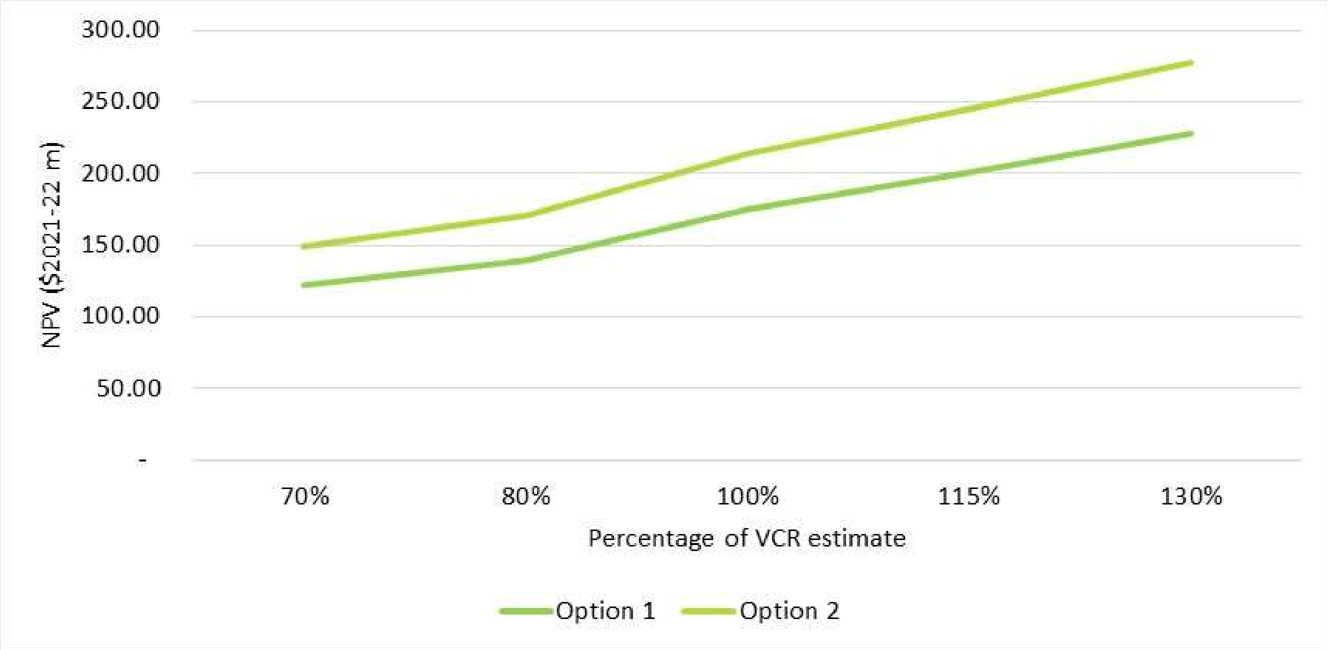
6.4.3. Value of customer reliability

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 6-4 Sensitivity of net economic benefits under a lower and higher VCR ($2021/22m)

Option/scenario	Low VCR	High VCR	Ranking
Sensitivity	*Central estimate - 30%*	*Central estimate + 30%*	
Option 1	122.25	227.73	2
Option 2	149.51	277.55	1

Figure 6-3 Sensitivity of net economic benefits under a lower and higher VCR ($2021/22 m)



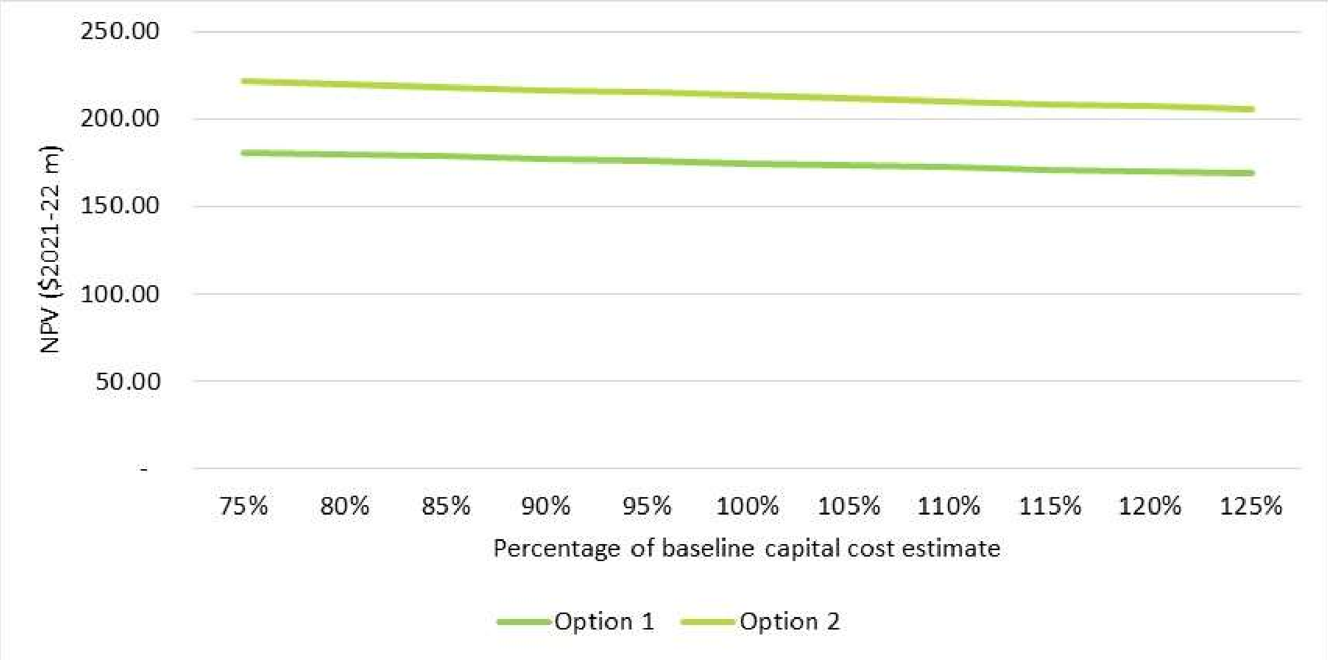
6.4.4. Network capital costs

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 6-4: Sensitivity of net economic benefits under lower and higher capital costs ($2021/22 m)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Central estimate - 25%*	*Central estimate + 25%*	
Option 1	181.17	168.81	2
Option 2	221.48	205.58	1

Figure 6-4 Sensitivity of net economic benefits under lower and higher capital costs ($2021/22 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 whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome. Our findings show that Option 2's capex would need to increase by more than 121% of its current baseline capex estimates in order to change the RIT-T outcome i.e., for Option 2's NPV net economic benefit to be less than Option 1's. Such a change in capital costs is outside the expected range of costs and, as such, this result of Option 2 being the preferred options is robust to reasonable capital cost sensitivities.

6.4.5. Discount rate

A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis presented in this PACR, with AEMO's Inputs Assumptions and Scenarios Consultation Report[28] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[29] 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 per cent.[30] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[31] The results of this analysis are presented in the table and figure below.

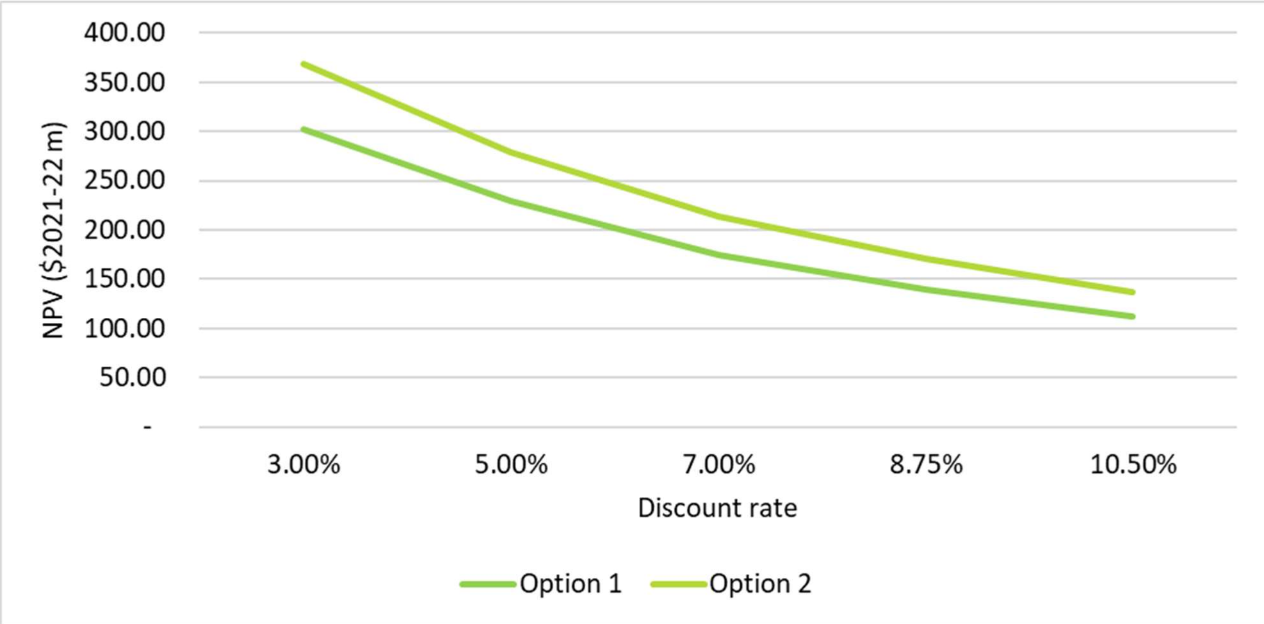
Table 6-5: Sensitivity of net economic benefits under a lower and higher discount rates ($2021/22 m)

Option/scenario	Low discount rate	High discount rate	Ranking

[28] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.
[29] AEMO, *2022 Integrated System Plan, June 2022*, p 91.
[30] 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
[31] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

Sensitivity	*3.0%*	*10.5%*	
Option 1	302.00	111.88	2
Option 2	368.27	136.61	1

Figure 6-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2021/22 m)



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our results suggest that there is no reasonable discount rate that would change the RIT-T outcome

7. Final conclusion on the preferred option

The analysis in this PACR finds that Option 2 is the preferred option to address the identified need. Under Option 2, 55 of the 122 identified circuit breakers will be replaced with a DTCB. For these circuit breakers, the associated current transformers will reach the end of their technical life by 2027/28. The remaining 67 of the 122 identified circuit breakers will be replaced with a LHCB. For these circuit breakers, either replacement with a DTCB is not technically feasible, there is no associated current transformer, or the current transfer has substantial remaining life.

The capital cost of this option is approximately $41.50 million (in $2021-22). The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. The annual routine operating and maintenance cost is forecast to decrease to $106,458 in 2028-29 under this option, increasing to $172,567 in 2041-42.

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.

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 204.

<table>
<tr><th>Rules clause</th><th>Summary of requirements</th><th>Relevant section(s) in the PACR</th></tr>
<tr><td rowspan="3">5.16.4(v)</td><td>The project assessment conclusions report must set out:</td><td>–</td></tr>
<tr><td>(1) the matters detailed in the project assessment draft report as required under paragraph (k); and</td><td>See below.</td></tr>
<tr><td>(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (q).</td><td>NA</td></tr>
<tr><td rowspan="11">5.16.4(k)</td><td>The project assessment draft report must include:</td><td>–</td></tr>
<tr><td>(1) a description of each credible option assessed;</td><td>3</td></tr>
<tr><td>(2) a summary of, and commentary on, the submissions to the project specification consultation report;</td><td>NA</td></tr>
<tr><td>(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;</td><td>3 & 6</td></tr>
<tr><td>(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;</td><td>4 & 5</td></tr>
<tr><td>(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;</td><td>4</td></tr>
<tr><td>(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);</td><td>NA</td></tr>
<tr><td>(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;</td><td>6</td></tr>
<tr><td>(8) the identification of the proposed preferred option;</td><td>7</td></tr>
<tr><td>(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.</td><td>3 & 7</td></tr>
<tr><td>(10) if each of the following apply to the RIT-T project:</td><td>NA</td></tr>
</table>

	(i) if the 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 RIT-T reopening triggers applying to the RIT-T project.	

Appendix B Circuit breakers identified for replacement

Table B-1 presents a list of the circuit breakers identified by this need and the proposed replacement approach under the preferred option (Option 2).

Table B-1: Circuit breakers considered under this RIT-T

Substation Name	Circuit breaker	Option 2 Replacement
DAPTO 330KV SS	NO1 TRANSFORMER 132KV A BUS CB BAY	Live Tank 132kV 50kA
DAPTO 330KV SS	NO3 TRANSFORMER 132KV A BUS CB BAY	Live Tank 132kV 50kA
DAPTO 330KV SS	NO3 TRANSFORMER 132KV B BUS CB BAY	Dead Tank 132kV 50kA
DAPTO 330KV SS	NO4 TRANSFORMER 132KV A BUS CB BAY	Live Tank 132kV 50kA
DAPTO 330KV SS	NO4 TRANSFORMER 132KV B BUS CB BAY	Dead Tank 132kV 50kA
DAPTO 330KV SS	98W MT TERRY 132KV FEEDER	Live Tank 132kV 50kA
DAPTO 330KV SS	982 SPRINGHILL 132KV FEEDER	Live Tank 132kV 50kA
DAPTO 330KV SS	988 FAIRFAX LANE TEE 132KV FEEDER	Live Tank 132kV 50kA
DAPTO 330KV SS	984 TALLAWARRA 132KV FEEDER	Dead Tank 132kV 50kA
REGENTVILLE SS	238 PENRITH 132KV FEEDER	Live Tank 132kV 40kA
REGENTVILLE SS	232 GLENMORE PARK 132KV FEEDER	Live Tank 132kV 40kA
REGENTVILLE SS	NO1 BUS COUPLER 132KV BAY	Live Tank 132kV 40kA
SYDNEY EAST SS	NO7 TRANSFORMER 132KV CB BAY	Live Tank 132kV 40kA
SYDNEY SOUTH SS	NO5 TRANSFORMER 330KV CB BAY	Dead Tank 330kV 50kA
SYDNEY SOUTH SS	13 KEMPS CREEK 330KV B BUS CB BAY	Live Tank 330kV 50kA
SYDNEY SOUTH SS	12 LIVERPOOL 330KV A BUS CB BAY	Live Tank 330kV 50kA
SYDNEY SOUTH SS	12 LIVERPOOL 330KV B BUS CB BAY	Live Tank 330kV 50kA
SYDNEY SOUTH SS	914 BANKSTOWN 132KV FEEDER BAY	Live Tank 132kV 40kA
SYDNEY WEST SS	NO2 TRANSFORMER 330KV CB BAY	Live Tank 330kV 50kA
SYDNEY WEST SS	NO3 TRANSFORMER 330KV CB BAY	Live Tank 330kV 50kA
SYDNEY WEST SS	1C HOLROYD 330KV B BUS CB BAY	Live Tank 330kV 50kA
SYDNEY WEST SS	32 BAYSWATER 330KV B BUS CB BAY	Live Tank 330kV 50kA
SYDNEY WEST SS	26 MUNMORAH 330KV A BUS CB	Live Tank 330kV 50kA
SYDNEY WEST SS	38 REGENTVILLE 330KV FEEDER BAY	Live Tank 330kV 50kA
SYDNEY WEST SS	NO3 TRANSFORMER 132KV B BUS CB BAY	Dead Tank 132kV 50kA
SYDNEY WEST SS	93U ABBOTSBURY 132KV FEEDER BAY	Live Tank 132kV 50kA
SYDNEY WEST SS	9J2 BLACKTOWN 132KV FEEDER BAY	Live Tank 132kV 50kA
SYDNEY WEST SS	9J1 BLACKTOWN 132KV FEEDER BAY	Live Tank 132kV 50kA
SYDNEY WEST SS	B1-2 132KV BUS SECTION	Dead Tank 132kV 50kA
VINEYARD 330 SS	25 ERARING 330KV A BUS CB BAY	Dead Tank 330kV 50kA
VINEYARD 330 SS	29 SYDNEY WEST 330KV C BUS CB BAY	Dead Tank 330kV 50kA

Substation Name	Circuit breaker	Option 2 Replacement
VINEYARD 330 SS	25 ERARING 330KV B BUS CB BAY	Dead Tank 330kV 50kA
VINEYARD 330 SS	NO2 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
VINEYARD 330 SS	227 HAWKESBURY 132KV FDR BAY	Dead Tank 132kV 40kA
VINEYARD 330 SS	NO1 BUS COUPLER 132KV BAY	Dead Tank 132kV 40kA
VINEYARD 330 SS	234 HAWKESBURY 132KV FDR BAY	Dead Tank 132kV 40kA
FORBES SS	94U PARKES 132 - 132KV FEEDER BAY	Live Tank 132kV 40kA
FORBES SS	896 WEST JEMALONG 66KV CB BAY	Live Tank 66kV 40kA
MT PIPER 500 SS	NO3 TRANSFORMER 132KV CB BAY/94Y FDR	Dead Tank 132kV 40kA
PARKES 132kV SS	NO2 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
PARKES 132kV SS	94U FORBES 132KV FEEDER BAY	Dead Tank 132kV 40kA
PARKES 132kV SS	94K WELLINGTON TEE WELLINGTON WEST 132KV	Dead Tank 132kV 40kA
PARKES 132kV SS	NO2 TRANSFORMER 66KV CB BAY	Dead Tank 66kV 40kA
PARKES 132kV SS	898 TRUNDLE 66KV FEEDER BAY	Dead Tank 66kV 40kA
WELLINGTON SS	94B BERYL 132KV FEEDER BAY	Live Tank 132kV 40kA
WELLINGTON SS	A1-2 132KV BUS SECTION CB	Live Tank 132kV 40kA
WELLINGTON SS	9GY DUBBO SOUTH 132KV FEEDER BAY	Live Tank 132kV 40kA
WELLINGTON SS	947 ORANGE NORTH TEE B'DONG 132 FDR BAY	Live Tank 132kV 40kA
NEWCASTLE 330SS	NO1 TRANSFORMER 132KV A BUS CB BAY	Live Tank 132kV 50kA
NEWCASTLE 330SS	96Z MARYLAND 132KV FEEDER	Live Tank 132kV 50kA
NEWCASTLE 330SS	NO1-2 132KV B BUS SECTION	Live Tank 132kV 40kA
NEWCASTLE 330SS	9NA BERESFIELD 132KV FEEDER	Live Tank 132kV 50kA
PT MACQ 132 SS	NO2 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
PT MACQ 132 SS	96G KEMPSEY 132KV FEEDER	Live Tank 132kV 40kA
WARATAH WEST SS	NO 3 TRANSFORMER 132KV A CIRCUIT BREAKER	Dead Tank 132kV 40kA
WARATAH WEST SS	NO 3 TRANSFORMER 132KV B CIRCUIT BREAKER	Dead Tank 132kV 40kA
WARATAH WEST SS	96Y MAYFIELD WEST 132KV FEEDER	Dead Tank 132kV 40kA
WARATAH WEST SS	962 TOMAGO 132 SS - 132KV FEEDER	Dead Tank 132kV 40kA
WARATAH WEST SS	96X KOORAGANG 132KV FEEDER	Dead Tank 132kV 40kA
WARATAH WEST SS	95N NEWCASTLE 132KV A BUS CB BAY	Dead Tank 132kV 40kA
WARATAH WEST SS	95N NEWCASTLE 132KV B BUS CB BAY	Dead Tank 132kV 40kA
ARMIDALE 330 SS	NO1 132KV CAPACITOR	Live Tank 132kV 40kA POW
COFFS HARBR SS	NO4 132KV CAPACITOR	Dead Tank 132kV 40kA POW

Substation Name	Circuit breaker	Option 2 Replacement
GUNNEDAH SS	NO1 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
GUNNEDAH SS	NO2 TRANSFORMER 132KV CB BAY	Live Tank 132kV 40kA
GUNNEDAH SS	969 TAMWORTH 132KV FEEDER	Live Tank 132kV 40kA
GUNNEDAH SS	9U3 BOGGABRI EAST TEE GUNNEDAH EAST 132	Live Tank 132kV 40kA
GUNNEDAH SS	NO1 TRANSFORMER 66KV CB BAY	Dead Tank 66kV 40kA
GUNNEDAH SS	NO2 TRANSFORMER 66KV CB BAY	Dead Tank 66kV 40kA
GUNNEDAH SS	88K GUNNEDAH 66 SS - 66KV FEEDER	Live Tank 66kV 40kA
GUNNEDAH SS	NO2 66KV BUS SECTION	Live Tank 66kV 40kA
GUNNEDAH SS	88L GUNNEDAH 66 SS - 66KV FEEDER	Live Tank 66kV 40kA
GUNNEDAH SS	877 KEEPIT PS 66KV FEEDER	Dead Tank 66kV 40kA
INVERELL SS	9U2 MOREE 132KV CB BAY	Live Tank 132kV 40kA
INVERELL SS	96N ARMIDALE 330 - 132KV CB BAY	Dead Tank 132kV 40kA
INVERELL SS	NO1 TRANSFORMER 66KV CB BAY	Dead Tank 66kV 40kA
INVERELL SS	733 GLEN INNES 66 - 66KV FEEDER	Dead Tank 66kV 40kA
INVERELL SS	734 INVERELL 66 - 66KV FEEDER	Dead Tank 66kV 40kA
LISMORE 330 SS	NO1 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
LISMORE 330 SS	NO2 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
LISMORE 330 SS	967 KOOLKHAN 132KV FEEDER	Dead Tank 132kV 40kA
LISMORE 330 SS	9U9 LISMORE 132KV FEEDER	Dead Tank 132kV 40kA
LISMORE 330 SS	NO2 132KV CAPACITOR	Dead Tank 132kV 40kA POW
LISMORE 330 SS	96L TENTERFIELD 132KV FEEDER	Dead Tank 132kV 40kA
MOREE SS	721 MOREE 66KV FEEDER	Live Tank 66kV 40kA
MOREE SS	722 MOREE 66KV FEEDER	Live Tank 66kV 40kA
TENTERFIELD 132	NO1 TRANSFORMER 22KV CB BAY	Live Tank 33kV 40kA
TENTERFIELD 132	NO3 (TIMBARRA MINE) 22KV CB BAY	Live Tank 33kV 40kA
TENTERFIELD 132	NO4 (TSC 22/11KV SS) 22KV CB BAY	Live Tank 33kV 40kA
TENTERFIELD 132	NO6 (TENTERFIELD TOWN) 22KV CB BAY	Live Tank 33kV 40kA
ALBURY 132 KV	NO2-3 132KV BUS SECTION	Dead Tank 132kV 40kA
BROKEN HILL SS	X2 BURONGA 220KV NO.1 REACTOR BAY	Live Tank 220kV 50kA POW
BROKEN HILL SS	X2 BURONGA 220KV NO.2 REACTOR BAY	Live Tank 220kV 50kA POW
BROKEN HILL SS	X4 BROKEN HILL MINES 220KV CB BAY	Live Tank 220kV 50kA
BURONGA 220 SS	X2 BROKEN HILL 220KV CB BAY	Live Tank 220kV 50kA
BURONGA 220 SS	X2 BROKEN HILL 220KV REACTOR BAY	Live Tank 220kV 50kA POW

Substation Name	Circuit breaker	Option 2 Replacement
BURONGA 220 SS	X3 BALRANDALD 220KV CB BAY	Live Tank 330kV 50kA
BURONGA 220 SS	0X1 RED CLIFFS 220KV CB BAY	Live Tank 330kV 50kA
DENILIQUIN SS	99L COLEAMBALLY 132 - 132KV FEEDER	Live Tank 132kV 40kA
DARLINGTON P SS	NO1 TRANSFORMER 132KV A BUS CB BAY	Dead Tank 132kV 40kA
DARLINGTON P SS	NO2 TRANSFORMER 132KV B BUS CB BAY	Dead Tank 132kV 40kA
DARLINGTON P SS	99T/1 COLEAMBALLY 132KV FEEDER	Dead Tank 132kV 40kA
DARLINGTON P SS	99R HAY CB BAY	Live Tank 132kV 40kA
DARLINGTON P SS	99K GRIFFITH 132KV FEEDER	Live Tank 132kV 40kA
FINLEY 132kV SS	NO1 TRANSFORMER 132KV CB BAY	Dead Tank 132kV 40kA
FINLEY 132kV SS	84B FINLEY 66KV FEEDER	Dead Tank 66kV 40kA
GRIFFITH 132KV	NO2 TRANSFORMER 132KV CB BAY	Live Tank 132kV 40kA
GRIFFITH 132KV	79F YENDA 33KV FEEDER	Dead Tank 33kV 40kA
GRIFFITH 132KV	79L BEELBANGERA 33KV FEEDER	Dead Tank 33kV 40kA
GRIFFITH 132KV	79R THARBOGANG 33KV BAY	Dead Tank 33kV 40kA
GRIFFITH 132KV	NO2-3 33KV BUS SECTION	Dead Tank 33kV 40kA
MURRAY 330 SWS	M13 Murray2 330kV B Bus CB Bay(Un.13-14)	Live Tank 330kV 50kA
MURRAY 330 SWS	M1 Murray1 330kV A Bus CB Bay(Units 1-2)	Live Tank 330kV 50kA
MURRAY 330 SWS	M3 Murray1 330kV B Bus CB Bay (Units 3-4)	Live Tank 330kV 50kA
MURRAY 330 SWS	M5 Murray1 330kV B Bus CB Bay (Units 5-6)	Live Tank 330kV 50kA
MURRAY 330 SWS	M7 Murray1 330kV A Bus CB Bay (Units 7-8)	Live Tank 330kV 50kA
WAGGA 330KV SS	132KV "A" BUS SECTION 1-2	Dead Tank 132kV 40kA
MUNYANG 132KV	NO1 TRANSFORMER 132KV CB BAY	Live Tank 132kV 40kA
MUNYANG 132KV	NO2 TRANSFORMER 132KV CB BAY	Live Tank 132kV 40kA
MUNYANG 132KV	97K COOMA TEE 132KV FEEDER	Live Tank 132kV 40kA
MARULAN 330KV	972 GOULBURN 132KV FEEDER	Dead Tank 132kV 40kA
MARULAN 330KV	98C FAIRFAX LANE 132KV FEEDER	Dead Tank 132kV 40kA

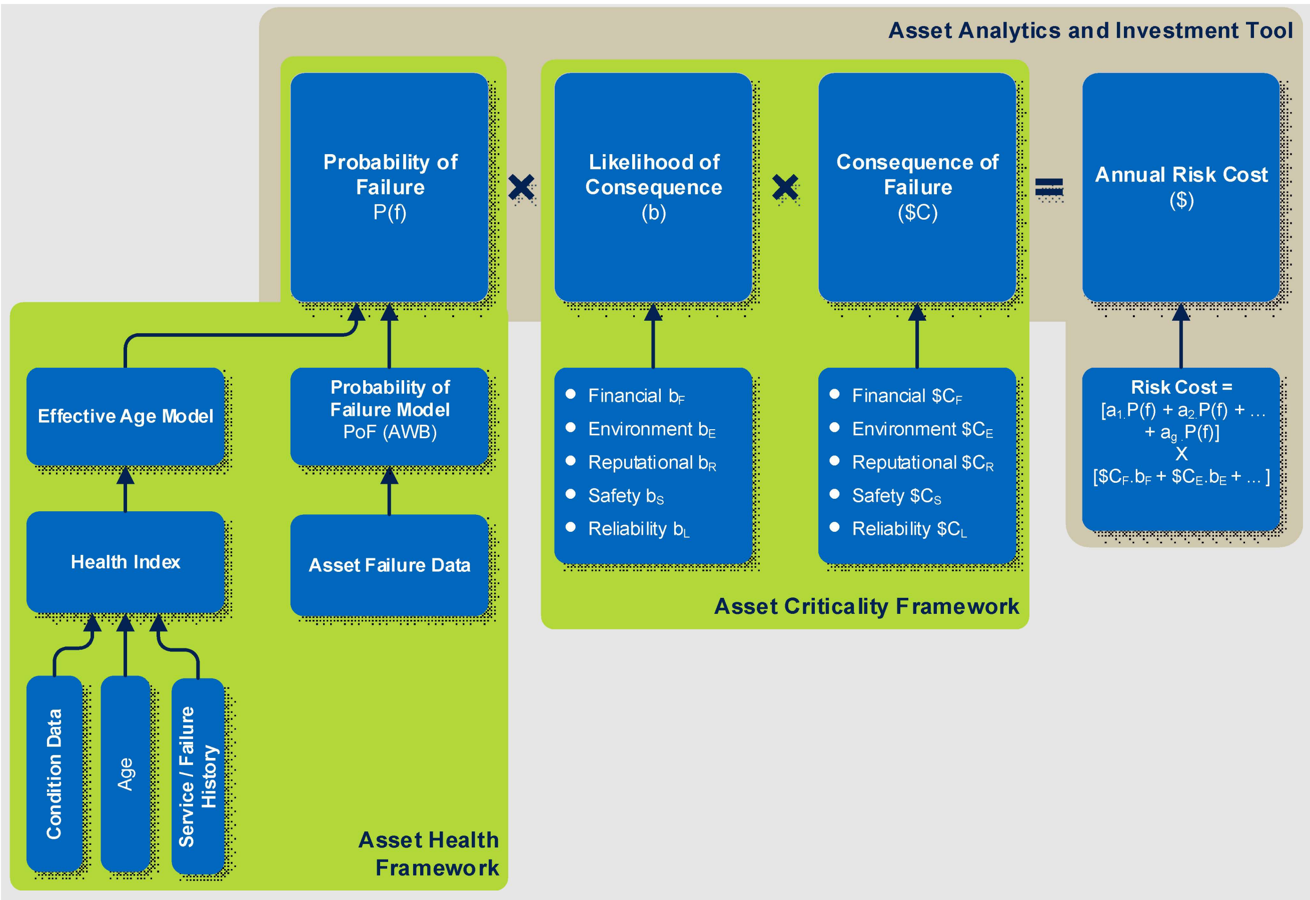
Appendix C Risk Assessment Methodology

Summary of methodology

This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline.[32]

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). The figure below summarises the framework for calculating the 'risk costs', which has been applied on our asset portfolio considered to need replacement or refurbishment.

Figure C-1 Risk cost calculation



Economic justification for replacement expenditure to address an identified need is provided where the risk reduction benefit (ie the value of avoided risk costs) is greater than the costs of the project or program. The

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major quantified risks we apply for replacement expenditure justifications include asset failures that materialise as:

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

The risk categories relevant to this RIT-T are explained in Section 2.3.

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

Asset health and Probability of Failure

The first step in calculating the Probability of Failure (PoF) of an asset is determining the asset health and associated effective age,[33] which considers that:

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

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

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

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

Further details are available in our Network Asset Health Methodology.

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

Table C-1 Weibull parameters for asset components

Asset	Weibull parameters	
	η	β
Circuit breakers	47.76	4.3
Oil CTs	50	3.08

Asset criticality

Asset criticality is the relative risk of the consequences of an undesired outcome. Asset criticality considers the severity of the consequences of the asset failure occurring and the likelihood the consequence will eventuate. Our approach to determining these factors for each relevant risk category is set out in our Network Asset Criticality Framework. The analysis leverages data from past events, relevant research / publications and technical insights, to determine an economic value of the impact.