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Maintaining safe and reliable operation of Beryl substation

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 maintaining the safe and reliable operation of Beryl Substation. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Beryl substation was commissioned in 1976 and forms part of our network that serves the central west NSW area and is supplied via two 132kV feeders (Line 94B and 94M), and feeds six customer 66kV lines operated by Essential Energy. 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. Although the central west NSW area is expected to experience strong growth over the next 10 years, with maximum demand forecast to grow by approximately 16% by 2032/33[1], Beryl Bulk Supply Point (BSP) is expected to have moderate load growth for next 10 years.

The condition of certain 132 kV and 66 kV high voltage and secondary system assets at Beryl 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 reactively rectify faults 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 Beryl substation

The identified need for this project is to maintain the safe and reliable operation of Beryl 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 rapidly deteriorate. 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 technological obsolescence. 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 RIT-T 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.

[1] Transgrid, NSW Transmission Annual Planning Report 2023, p.138.

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 capex estimate for Option 1
- Updated the discount rate used
- Updated the Value of Customer Reliability (VCR)

At the time the PSCR was published, the cost estimate for Option 1 was primarily based on a desktop assessment of the activity required to replace the high voltage and secondary systems assets. As we progressed to concept designs, we identified several changes that were not identified in the original assessment. The key changes are associated with existing conduits not being suitable for re-use and the capacitor footing needing to be re-built. Some minor compliance related items including lighting, and a new earth switch for clearances also contributed to an increase in the estimate.

The PSCR included the replacement of 6 disconnectors as part of Option 1, however utilisation of local site staff knowledge has enabled us to consider alternative methods to address the identified asset issues. Therefore, the replacement of the identified disconnectors has been removed from the current scope and no longer being addressed by this RIT-T. While the removal of the disconnectors resulted in a slight decrease in the overall capital expenditure estimate, the additional changes at concept design stage that are described above have resulted in an increase in the total capital expenditure for Option 1. Specifically, the capital expenditure estimate from Option 1 has increased from $7.06m ($2021-22) in the PSCR to $8.60m ($2021-22) in this PACR.

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[2] 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.[3] While we acknowledge this important change to the RIT-T, we note that there is not expected to be a difference in greenhouse gas emission levels because there is no change in options by implementing the emission change into the NPV. Therefore, this new category of market benefit is not expected to be material for this RIT-T and so has not been estimated.

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

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2 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.

3 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.

Credible options considered

We identified one credible network option that meets the identified need from a technical, commercial, and project delivery perspective[4]. This option is summarised in Table E-1.

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

Option	Description	Capital costs, ($m, 2021-22)	Operating costs (per year), $
Option 1	Targeted replacement of high voltage and secondary system assets	8.60	14,748

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
Protection relays	Line 94B 132kV – No2 Protection 66kV Capacitor No.2 - No1 Protection 66kV Capacitor No.2 - No2 Protection 66kV Capacitor No.3 - No1 Protection 66kV Capacitor No.3 - No2 Protection 66kV Capacitor No.4 - No1 Protection 66kV Capacitor No.4 - No2 Protection Line 86J 66kV – No1 Protection Line 86J 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 381 66kV – No1 Protection Line 381 66kV – No1 Protection Line 851 66kV – No1 Protection Line 851 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 852 66kV – No1 Protection Line 852 66kV – No1 Protection
Control systems	110V DC Supply – No1. Battery 110V DC Supply – No1. Charger 110V DC Supply – No2. Battery 110V DC Supply – No2. Charger

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

Metering systems	Transformer No.2 - Revenue metering Transformer No.2 - Check metering Transformer No.3 - Revenue metering Transformer No.3 - Check metering
Capacitor banks	66kV 10MVAr No.2 Capacitor Bank
Current transformers	66kV No.3 Transformer

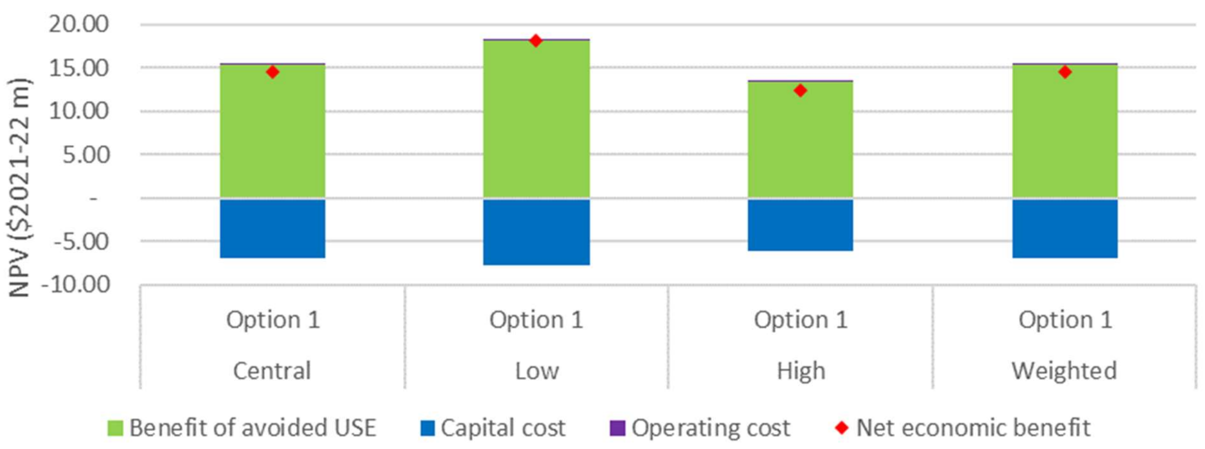
Non-network options are not expected to assist in this RIT-T

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T. 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. In addition, we did not receive any submissions from proponents of these solutions in response to the PSCR.

Conclusion: targeted replacement of high voltage and secondary system assets at Beryl substation is optimal

We have assessed that Option 1 is net beneficial under all three reasonable scenarios considered in this PSCR. On a weighted basis, where each scenario is weighted equally, Option 1 is expected to deliver net benefits of approximately $14.55m. Option 1 will also enable us to meet 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.

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



The capital cost of this option is approximately $8.60 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 $14,748 per annum (in $2021-22).

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.

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 'Beryl substation renewal PACR'.

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

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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 maintaining the safe and reliable operation of Beryl substation.

Beryl 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. Although the Central West NSW area is expected to experience strong growth over the next 10 years, with maximum demand forecast to grow by approximately 16% by 2032/33[6], Beryl Bulk Supply Point (BPS) is expected to have moderate load growth for next 10 years.

The condition of certain 132 kV and 66 kV high voltage and secondary system assets at Beryl substation has deteriorated over time leading to an increasing risk of failure which could result in reliability, safety, environmental and financial consequences. The secondary systems assets are also impacted by technological obsolescence of assets, increasing the time to reactively rectify faults and increasing the risk that primary assets at the substation may not be able to reliably operate.

The purpose of this RIT-T is to examine and consult on options to address the deterioration of the high voltage and secondary systems asset condition and the risk from technology obsolescence of the secondary systems at Beryl substation.

1.1. Purpose of this report

The purpose of this PACR[7] 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.

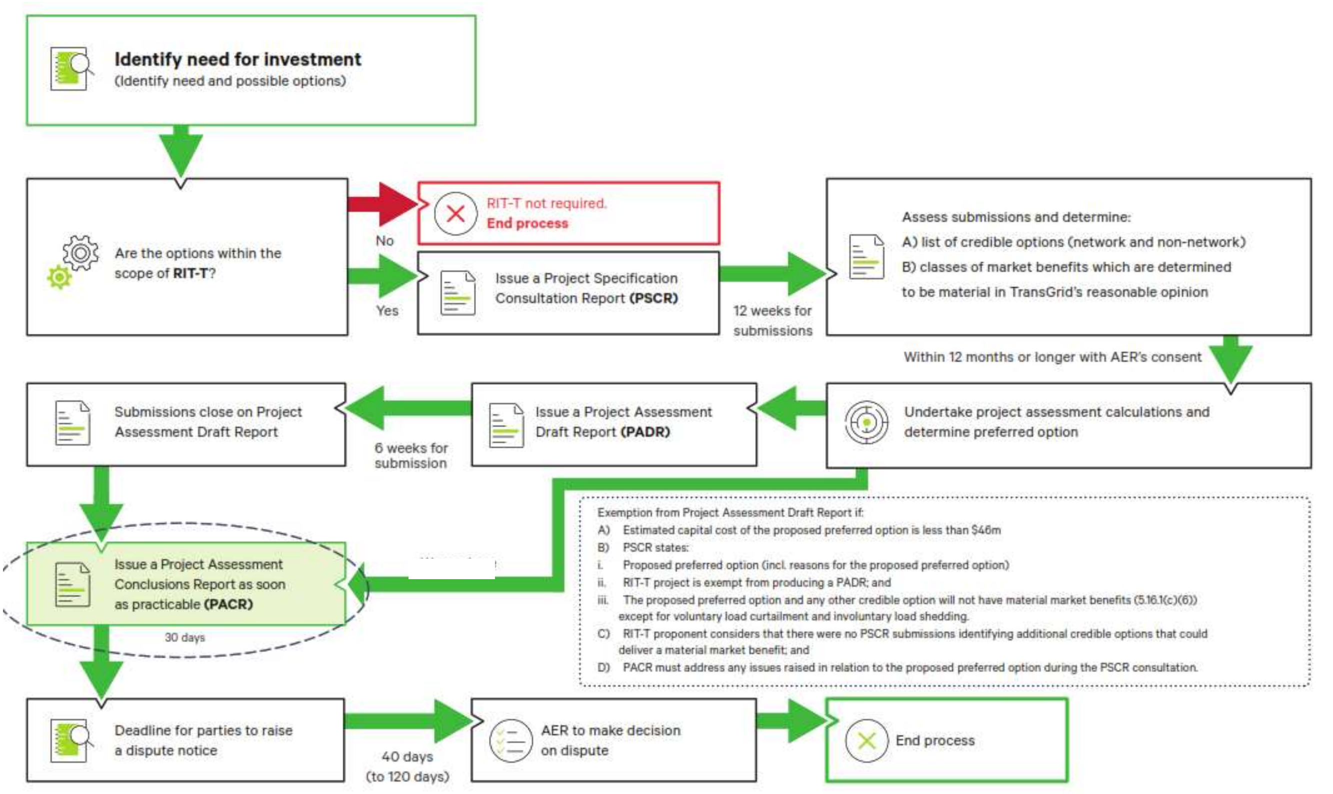
[6] Transgrid, NSW Transmission Annual Planning Report 2022, p.128.
[7] See Appendix A for the National Electricity Rules requirements.

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

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.

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



Parties wishing to raise a dispute notice with the AER may do so prior to 23 January 2024[9] (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 'Beryl substation renewal PACR'.

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

9 Additional days have been added to cover public holidays

2. The identified need

This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out background information related to the Central transmission network and existing electricity supply arrangements.

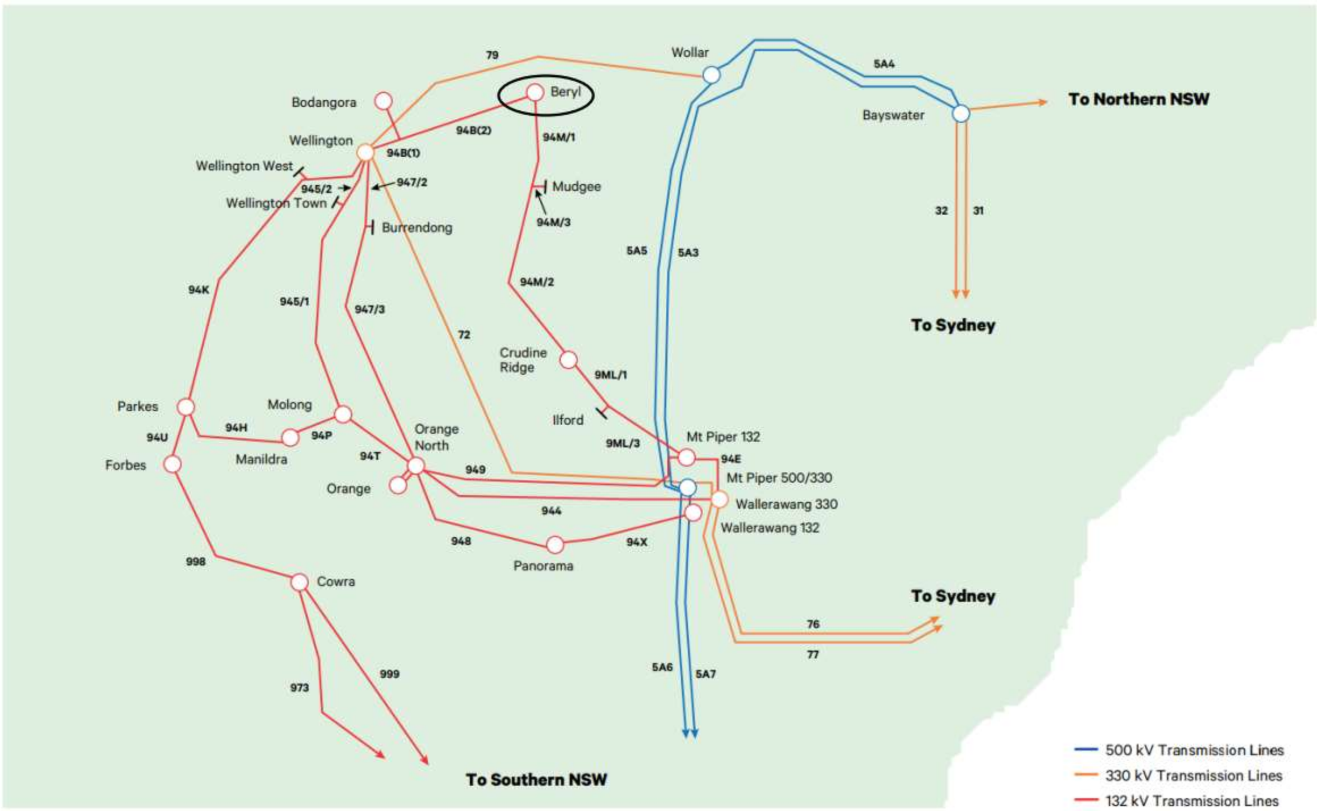
2.1. Background to the identified need

Beryl substation was commissioned in 1976 and forms part of our network that serves the central west NSW area. It is supplied via two 132kV feeders (Line 94B and 94M) and feeds six customer 66kV lines operated by Essential Energy. These 66kV feeders run between Beryl substation and Essential Energy substations in the surrounding area, including the Mudgee, Ulan and Dunedoo regions. The Beryl substation is comprised of two 132/66kV transformers, one 66kV frequency injection feeder, and three 66kV capacitor banks.

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

Figure depicts the location of Beryl substation on our network.

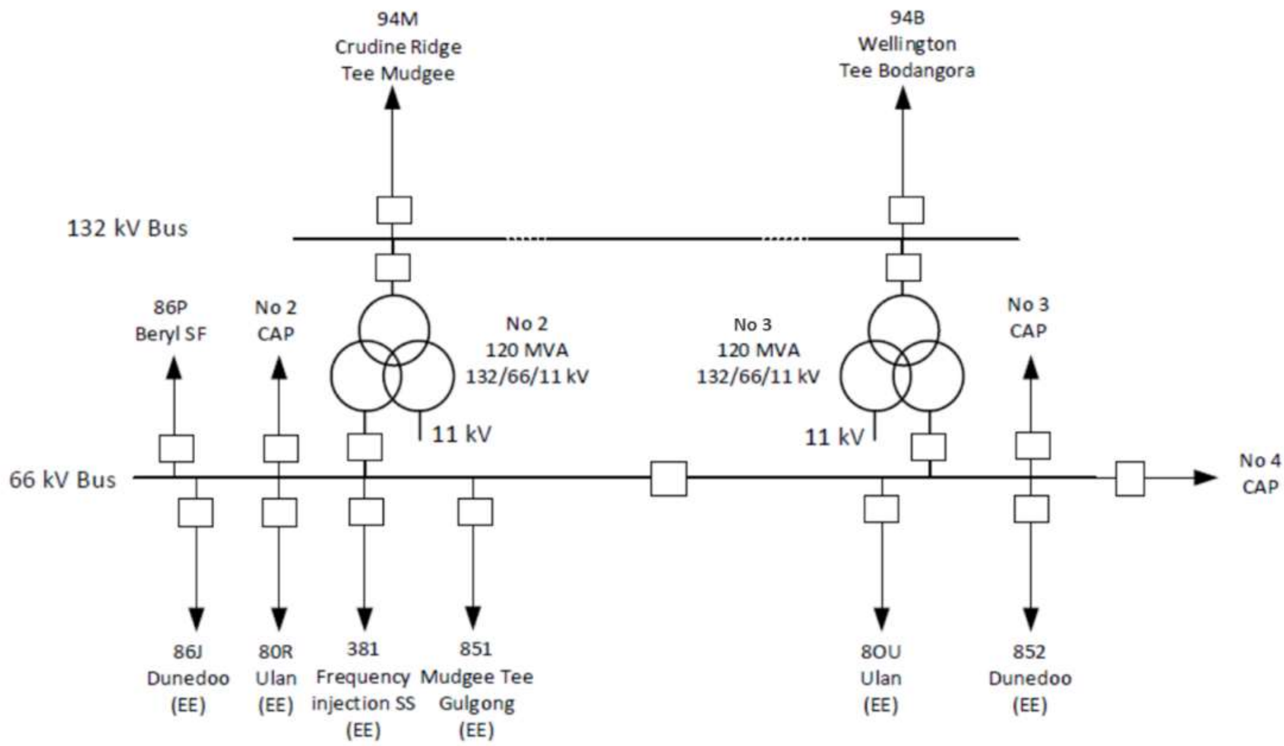
Figure 2-1 Location of Beryl substation



Official

Beryl 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. Although the central NSW area is expected to experience strong growth over the next 10 years, Beryl BSP is expected to have moderate growth. Maximum demand in Beryl BSP is forecast to be 91MW in 2023/24 Summer, and to increase to approximately 93 MW by 2032/33 (an increase of around 2%).[10]

Figure 2-2 Beryl 132kV substation electrical layout



2.2. Description of the identified need

The identified need for this project is to maintain the safe and reliable operation of Beryl 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 rapidly deteriorate. This will increase the risk of supply interruptions to our customers as well as safety, environmental and financial consequences.

Secondary systems are used to control, monitor, protect and secure 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. While the replacement of failed

10 Transgrid, NSW Transmission Annual Planning Report 2023, p.138.

secondary systems component is a possible interim measure, the approach is not sustainable as spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, asset replacement will cease to be a viable option to meet performance standards applicable to Beryl substation secondary systems. Increasing failure rates, along with the increased time to rectify faults due to the obsolescence of the equipment, significantly affects the availability and reliability of the secondary systems at Beryl 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[11]. 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. In addition, clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

2.3. Assumptions underpinning the identified need

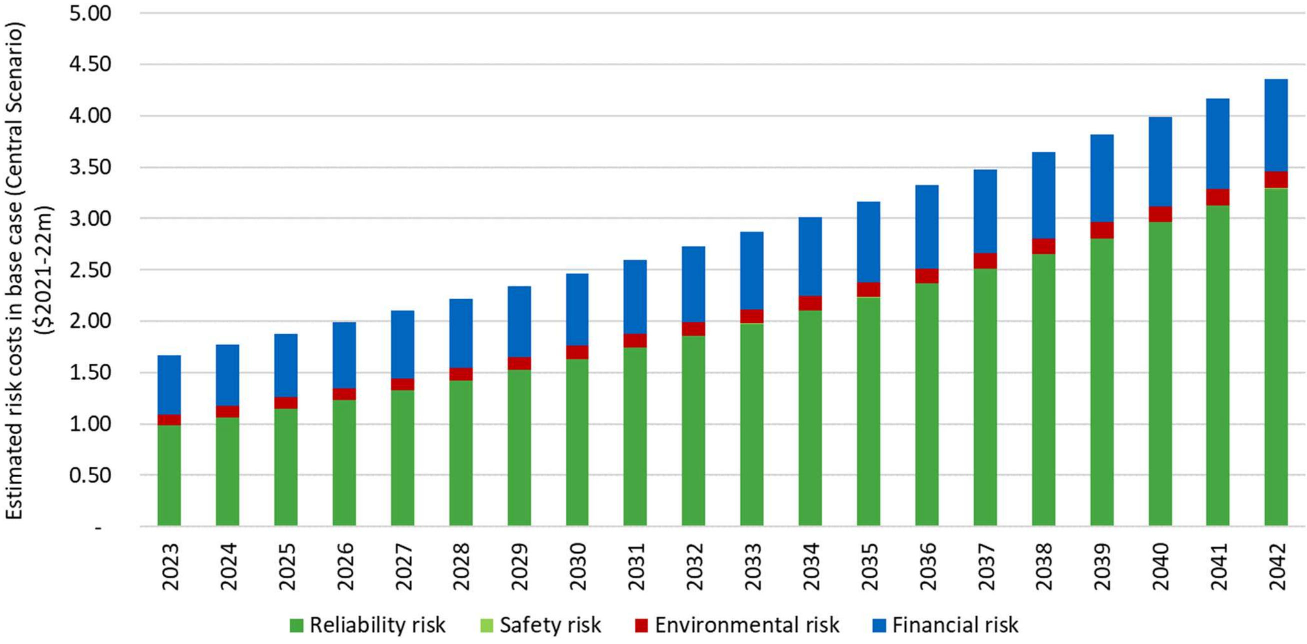
We adopt a risk cost framework to quantify and evaluate the risks and consequences of increased failure rates. Appendix B provides an overview of our risk assessment methodology.

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

[11] AEMO, Power System Security Guidelines, 6 February 2023, p.33.

Figure 2-3 Estimated risk costs under the central scenario ($m, real 2021/22)



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 $1.67 million/year and it is expected to increase going forward if action is not taken and the line is left to deteriorate further (reaching approximately $2.5 million/year by 2030 and $4.4 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. Protection relays

Protection relays are assets that monitor the network and trip circuit breakers when an abnormality in the network is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the NER.[12]

The protection relays at Beryl substation experiencing increasing failure rates, manufacturer obsolescence and a lack of support are targeted for replacement. The protection relays considered for replacement in this RIT-T are listed in Appendix B.

The protection relays are at or beyond the end of their technical life. 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

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

with the NER, including requirements around maintaining adequate protection systems[13] and maximum clearance times.[14]

2.3.1.2. Control systems

Control assets allow for the remote monitoring, control and automation of primary assets. These assets allow us to operate and monitor the status of unmanned substations and switching stations throughout the state. These assets also collect significant amounts of status and condition information to facilitate some level of remote diagnostics during failures and faults. The control systems considered for replacement in this RIT-T are listed in Appendix B .

These control systems have reached the end of their technical life, increasing the risk that they will not operate properly when required. A failure of control systems will significantly undermine our ability to operate the substation remotely, and to detect failures in other substation assets when they occur. Replacement of these control systems is required to ensure compliance with the NER, including requirements to ensure that remote monitoring and control systems are maintained in accordance with the standards and protocols determined and advised by AEMO.[15]

2.3.1.3. Metering systems

Metering systems located at customer connection points in our substations record the amount of power being transmitted at that point. Their purpose is to provide metering data for NEM settlement. The metering systems considered for replacement in this RIT-T are listed in Appendix B.

The identified metering assets have reached the end of their technical life, increasingly the likelihood of asset failure. If a malfunction occurs, clause 7.8.10 of the NER requires us to repair the metering system within 2 days. However, technological obsolescence means that access to spares and manufacturer support is limited. This will increase the time required to undertake the repair, and so the likelihood that the asset may be out of service for an extended period of time in breach of clause 7.8.10 of the NER.

2.3.1.4. Capacitor banks

Capacitor banks are required to ensure that system voltage levels are maintained within ±10% of nominal voltage which is a requirement under the NER Clause S5.1.a.4. The capacitor banks considered for replacement in this RIT-T are listed in Appendix B.

In assessing the ongoing viability of this capacitor bank, we have considered several factors. This includes existing holdings of spares and the ability to source more spares; the general condition of the equipment; and its age. The identified capacitor bank has been in service longer than its expected economic life, which is 30 years. We do not currently hold any spare reactors, and only possess a limited number of spare cans which are expected to deplete quickly. Given its age, the ability to source additional spares in a reasonable time period is challenging due to reduced manufacturer support.

If left unreplaced, the likelihood that the identified capacitor bank will fail is expected to increase significantly as the capacitor bank continues to age. If the capacitor bank is not available at times of high load, load shedding will be required to take place for customers in central west NSW to ensure that system voltage levels remain within ±10% as required by the NER.[16] Given the limited availability of spares, the

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[13] NER, s5.1.2.1(d) and s5.1.9(c).
[14] NER, s5.1a.8.
[15] NER, clause 4.11.1.
[16] NER, clause S5.1.a.4.

duration of such outages will also be expected to increase over time. On the basis of this assessment, we consider that replacing the identified capacitor bank would be expected to result in economic benefits for consumers by reducing the risk of load shedding.

2.3.1.5. Current transformers

Current transformers (CTs) are high voltage equipment whose purpose on the network is to transform main system current levels to a range that is useable by secondary systems equipment. CTs are typically installed in a set of three in a switch bay and are essential for the control, protection and revenue metering of the high voltage network. The current transformers considered for replacement in this RIT-T are listed in Appendix B.

The identified CTs at Beryl substation are oil filled CTs. These assets will reach the end of their economic life before 2027/28. As oil filled CTs age, the following conditions materialise which increase the risk of asset failure:

- Degradation of the high voltage oil and paper insulation system due to electrical stress
- Oil leaks due to degradation of seals and outer housing
- Corrosion due to weathering

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. Oil filled CTs have the highest risk of explosive failure which can result in the risk of injuring people, cause collateral damage and outages of nearby services due to the porcelain insulator being ejected from the failed asset, and other environmental issues such as fires. Replacing the identified CTs at Beryl substation will reduce the risk of involuntary load shedding for customers in Central West NSW, and reduce the risk of safety and environmental hazards associated with any catastrophic failures occurring.

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 PSCR. 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 67.46 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 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 0.06 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 4.96 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 27.52 per cent of the total estimated risk cost in present value terms.

3. Potential credible options

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.[17] This involves targeted replacement of the high voltage and secondary systems assets at Beryl 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. We do not consider non-network options to be technically or commercially 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.

3.1. Base case

The costs and benefits of each option in this PACR are compared against those of a base case.[18] Under this base case, no proactive capital investment is made to remediate the deterioration of the identified assets and the lines will continue to operate and be maintained under the current regime.

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

Table 3-1 below provides a breakdown of the base case operating expenditure by asset category.

Table 3-1 Breakdown of base case operating expenditure by asset category ($2021-22)

Item	Capital expenditure ($2021-22)	Operating expenditure ($2021-22)
Protection relays	-	9,838
Control systems	-	-
Metering systems	-	3,606
Capacitor banks	-	1,000
Current transformers	-	1,400
Total	**-**	**15,844**

Table 3-2 Annual breakdown of capital and operating costs for the base case ($2021-22)

Years	Capital expenditure	Operating expenditure
2023	-	$15,844
2024	-	$15,844

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

18 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.

2025	-	$15,844
2026	-	$15,844
2027	-	$15,844
2028	-	$15,844
2029	**-**	$15,844
2030	**-**	$15,844
2031	**-**	$15,844
2032	**-**	$15,844
2033	**-**	$15,844
2034	**-**	$15,844
2035	**-**	$15,844
2036	**-**	$15,844
2037	-	$15,844
2038	-	$15,844
2039	-	$15,844
2040	-	$15,844
2041	-	$15,844
2042	-	$15,844
Total	**-**	**$316,881**

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 Beryl 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 Beryl 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 Beryl substation will increase from approximately $0.99 million in 2022/23 to approximately $0.11 million in 2032/33 (in $2021-22). 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 $685,165 in 2022/23 and increase to $896,860 in 2032/33 (in $2021-22).

3.2. Option 1 – Targeted asset replacement at Beryl substation

Option 1 involves targeted replacement of high voltage and secondary system assets at Beryl 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
Protection relays	Line 94B 132kV – No2 Protection 66kV Capacitor No.2 - No1 Protection 66kV Capacitor No.2 - No2 Protection 66kV Capacitor No.3 - No1 Protection 66kV Capacitor No.3 - No2 Protection 66kV Capacitor No.4 - No1 Protection 66kV Capacitor No.4 - No2 Protection Line 86J 66kV – No1 Protection Line 86J 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 381 66kV – No1 Protection Line 381 66kV – No1 Protection Line 851 66kV – No1 Protection Line 851 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 852 66kV – No1 Protection Line 852 66kV – No1 Protection
Control systems	110V DC Supply – No1. Battery 110V DC Supply – No1. Charger 110V DC Supply – No2. Battery 110V DC Supply – No2. Charger
Metering systems	Transformer No.2 - Revenue metering Transformer No.2 - Check metering Transformer No.3 - Revenue metering Transformer No.3 - Check metering
Capacitor banks	66kV 10MVAr No.2 Capacitor Bank
Current transformers	66kV No.3 Transformer

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 $8.6 million (in $2021-22). This cost is comprised of $3.1m in labour costs, $1.5m in materials costs, and $4.0m in expenses.

Table 3-4 Breakdown of Option 1 capital and operating expenditure by asset category ($2021-22)

Item	Capital expenditure ($2021-22)	Operating expenditure ($2021-22)
Protection relays	$3,428,000	$249,159
Control systems	$173,500	-
Metering systems	$366,000	$100,979
Capacitor banks	$4,400,000	$28,000
Current transformers	$232,500	$39,200
Total	**$8,600,000**	**$417,338**

Table 3-5 Annual breakdown of capital and operating costs for Option 1 ($2021-22)

Years	Capital expenditure	Operating expenditure
2023	$1,607,000	$15,844
2024	$4,380,000	$15,844
2025	$793,500	$15,625
2026	$793,500	$15,406
2027	$1,026,000	$15,187
2028	-	$14,968
2029	-	$14,748
2030	-	$14,748
2031	-	$14,748
2032	-	$14,748
2033	-	$14,748
2034	-	$14,748
2035	-	$14,748
2036	-	$14,748
2037	-	$14,748
2038	-	$14,748
2039	-	$14,748
2040	-	$14,748

2041	-	$14,748
2042	-	$14,748
Total	**$8,600,000**	**$417,338**

The routine operating and maintenance costs are estimated at approximately $14,784 per annum (in $2021-22). We expect that the new protection relays, control systems, and metering systems will have an asset life of 15 years, the capacitor banks will have an asset life of 35 years, and the disconnectors and current transformers will have an asset life of 40 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 Beryl 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.

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
Complete in-situ replacement of protection relays, control systems, and metering systems and targeted replacement of the high voltage equipment	This option cannot be delivered in sufficient time to meet the identified need due to resource constraints imposed by our overall portfolio of work. This option would also be higher cost than the credible option assessed to meet the identified need.

3.4. No material inter-network impact is expected

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

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

[19] 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:[20]

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

We note that Option 1 satisfies these conditions as it does not modify any aspect of electrical or transmission assets. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with Option 1.

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

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.[21]

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[22] 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.[23] While we acknowledge this important change to the RIT-T, we note that there is not expected to be a difference in greenhouse gas emission levels because there is no change in options by implementing the emission change into the NPV. Therefore, this new category of market benefit is not expected to be material for this RIT-T and so has not been estimated.

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 Beryl 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 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.[24]

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

[22] 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.

[23] 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.

[24] 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;
- competition benefits; and

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.[25] 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.[26] 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.

[25] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p.53-54.
[26] 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 proactive capital investment is made to remediate the deterioration of the high voltage and secondary systems assets at Beryl 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 Beryl 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.[27]

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 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 as the central assumption for the NPV analysis presented in this PACR, consistent 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

[27] 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,* August 2020, p.21).

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

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

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]

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.

As Beryl is an active substation, no additional allowance has been made for access, as existing access will be suitable. Similarly, no additional allowance has been made for poor soil due to all works occurring within a live substation.

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).[32]

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[33]. 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').

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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.

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

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

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

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).[34],[35],[36]

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.

[34] AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, pp. 40-41.
[35] 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.
[36] 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 PSCR 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 capital costs and the discount rate beyond which the outcome of the analysis would change:

- capital costs would have to increase by 212.94 per cent;
- a discount rate of 28.98 per cent.

These boundaries where Option 1 would no longer be top ranked are extreme and are unlikely to eventuate. We therefore consider the finding that Option 1 is preferred over the Base Case to be robust to the key underlying assumptions.

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

Figure below summarises the present value of the gross benefits of Option 1 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 ($m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	20.54	24.10	18.10	20.54

6.2. Estimated costs

Table 6-2 below summarises the costs of Option 1, relative to the base case, in present value terms. 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 6-2 Costs of credible options relative to the base case ($m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	6.83	7.77	6.14	6.83

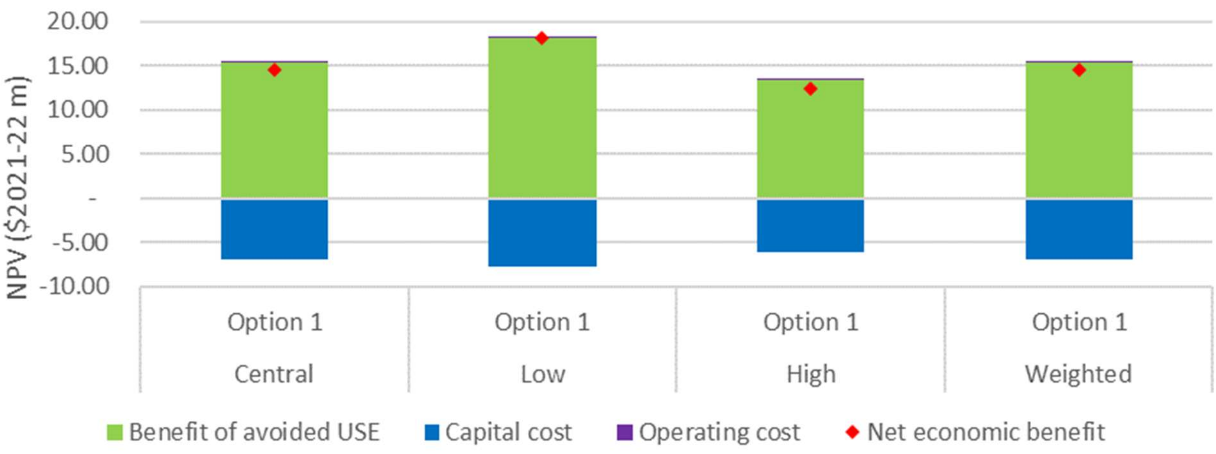
6.3. Estimated net economic benefits

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 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	14.55	18.21	12.39	14.55

Figure 6-1 Net economic benefits ($m, PV)



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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.

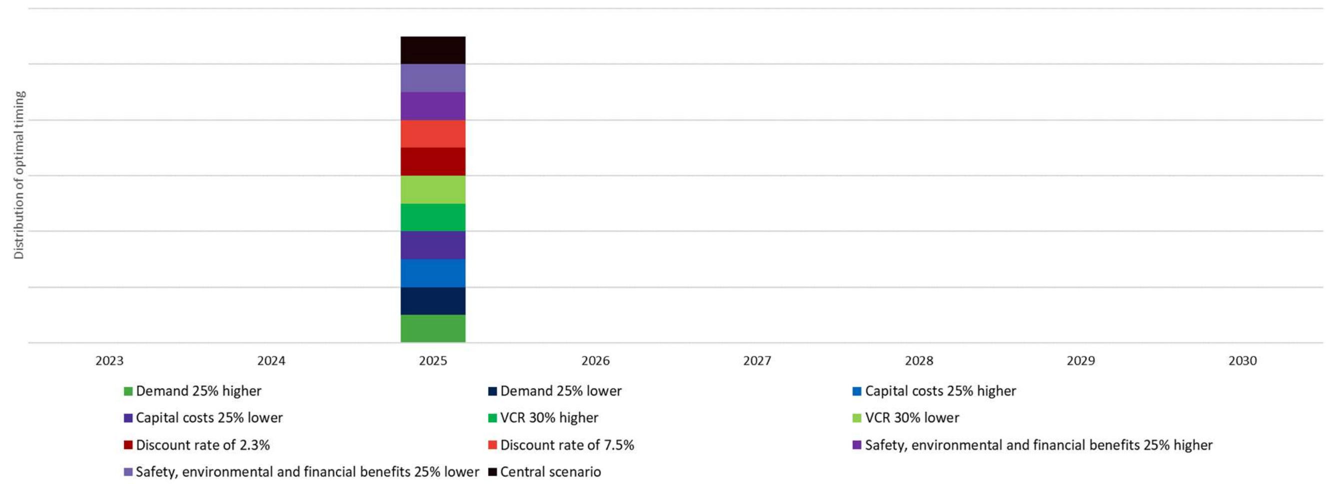
The sensitivities we considered are:

- a 25% increase / decrease in capital costs
- a 25% increase / decrease in demand
- a lower discount rate of 2.3% and a higher discount rate of 7.5%
- 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 2024/25. That is, the annual benefits from the first stage of the Beryl substation renewal (capacitor bank replacement) is higher than the annualised investment costs, even before benefits ramp up from 2028/29 when the entire substation renewal is complete.

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 Beryl substation renewal 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

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).

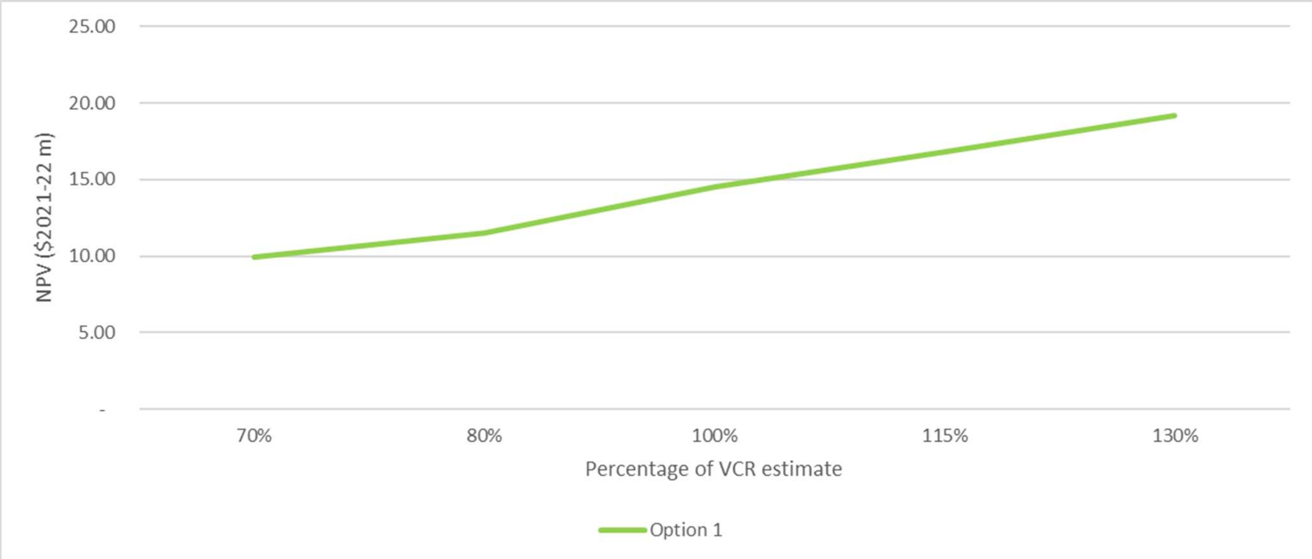
6.4.3. Value of customer reliability

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 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	9.96	19.15	1

Figure 6-1 Sensitivity of net economic benefits under a lower and higher VCR ($2021/22 m)



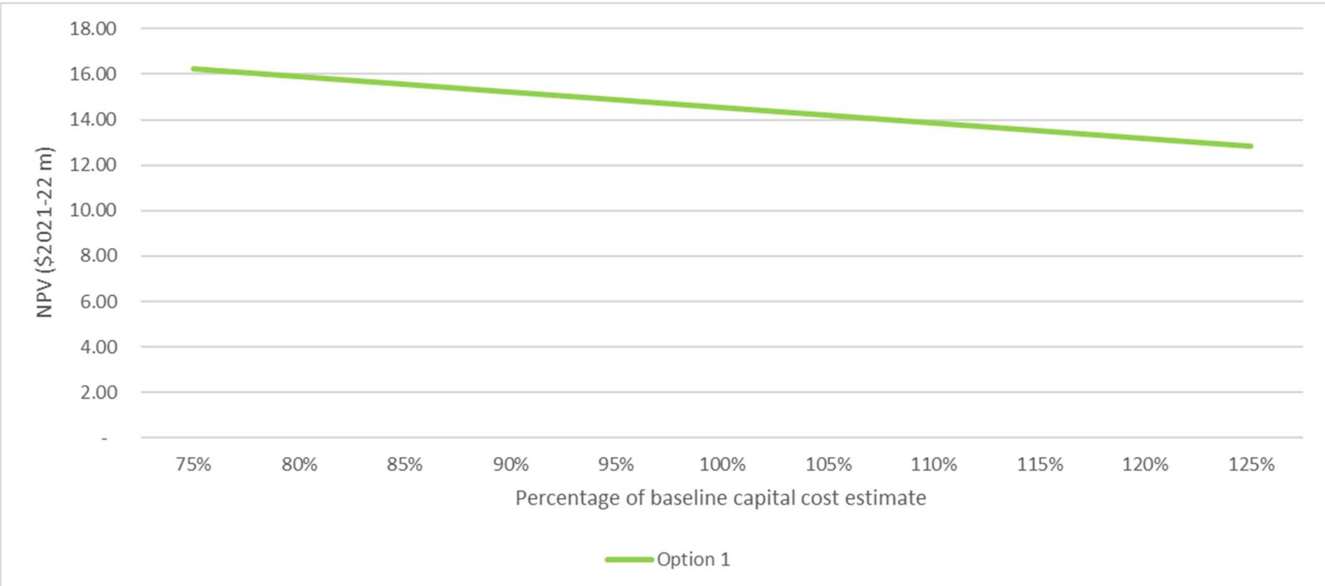
6.4.4. Network capital costs

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 6-5: 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	16.26	12.84	1

Figure 6-2: 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 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 1240% 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

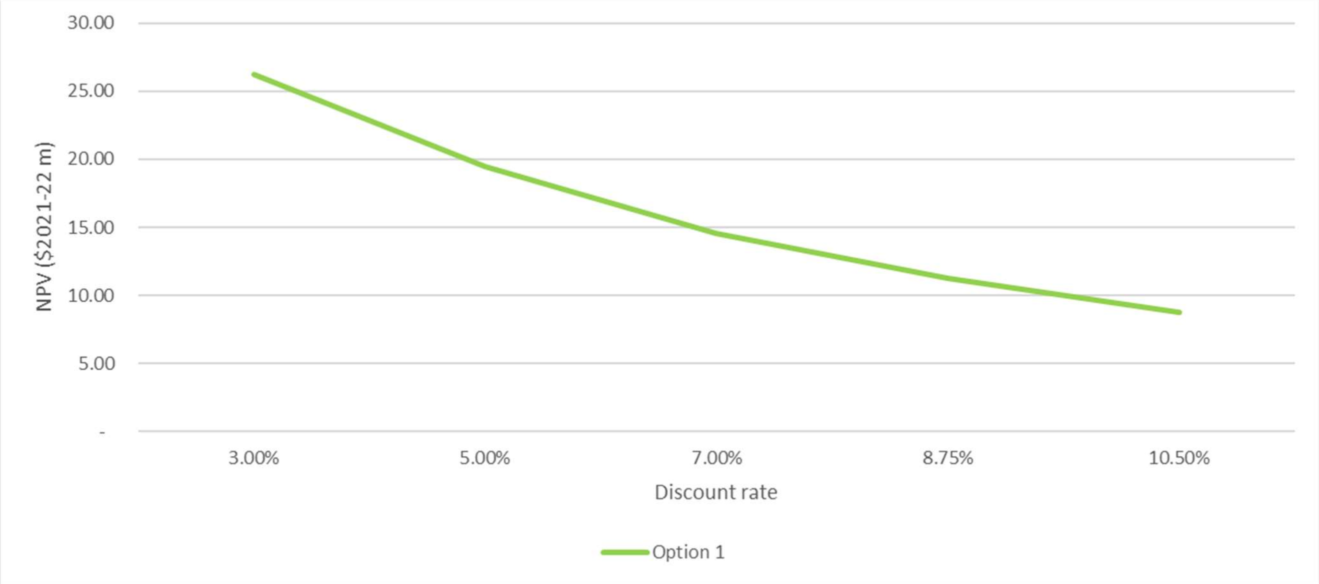
A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis presented in this PACR, with AEMO's Inputs Assumptions and Scenarios Consultation Report[37] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[38] The RIT-T requires that 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.[39] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[40] The results of this analysis are presented in the table and figure below.

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

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*3.0%*	*10.5%*	
Option 1	26.24	8.77	1

[37] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.
[38] AEMO, *2022 Integrated System Plan, June 2022*, p 91.
[39] 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
[40] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

Figure 6-3 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 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

The analysis in 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 Beryl 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 $8.6 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 $14,748 per annum (in $2021/22).

As Beryl is an active substation, no additional allowance has been made for access, as existing access will be suitable. Similarly, no additional allowance has been made for poor soil due to all works occurring within a live substation.

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 and 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 204.

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

	The RIT-T reopening triggers applying to the RIT-T project.	

Transgrid

Appendix B List of assets to be replaced under Option 1

Table B-1 presents a list of the protection relays to be replaced under Option 1.

Table B-1: Protection relays considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
Line 94B 132kV – No2 Protection	11	Exceeded technical life and relay type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
66kV Capacitor No.2 - No1 Protection	54	
66kV Capacitor No.2 - No2 Protection	54	
66kV Capacitor No.3 - No1 Protection	13	
66kV Capacitor No.3 - No2 Protection	12	
66kV Capacitor No.4 - No1 Protection	13	
66kV Capacitor No.4 - No2 Protection	12	
Line 86J 66kV – No1 Protection	13	
Line 86J 66kV – No1 Protection	12	
Line 80R 66kV – No1 Protection	37	
Line 80R 66kV – No1 Protection	37	
Line 381 66kV – No1 Protection	12	
Line 381 66kV – No1 Protection	15	
Line 851 66kV – No1 Protection	16	
Line 851 66kV – No1 Protection	13	
Line 80U 66kV – No1 Protection	37	
Line 80U 66kV – No1 Protection	37	
Line 852 66kV – No1 Protection	16	
Line 852 66kV – No1 Protection	37	
Line 94B 132kV – No2 Protection	11	
66kV Capacitor No.2 - No1 Protection	54	

Table B-2 presents a list of the control systems to be replaced under Option 1.

Table B-2: Control systems considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
110V DC Supply – No1. Battery	16	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
110V DC Supply – No1. Charger	23	
110V DC Supply – No2. Battery	13	
110V DC Supply – No2. Charger	15	

Table B-3 presents a list of the metering systems to be replaced under Option 1.

Table B-3: Metering systems considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
Transformer No.2 - Revenue metering	15	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
Transformer No.2 - Check metering	14	
Transformer No.3 - Revenue metering	15	
Transformer No.3 - Check metering	14	

Table B-4 presents a list of the capacitor banks to be replaced under Option 1.

Table B-4: Capacitor banks considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
66kV No.2 Capacitor Bank	45	Condition deterioration. Limited spare capacitor cans and no spare reactors.

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

Table B-5: Transformers considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
66kV No.3 Transformer	36	Condition deterioration

Appendix C Risk Assessment Methodology

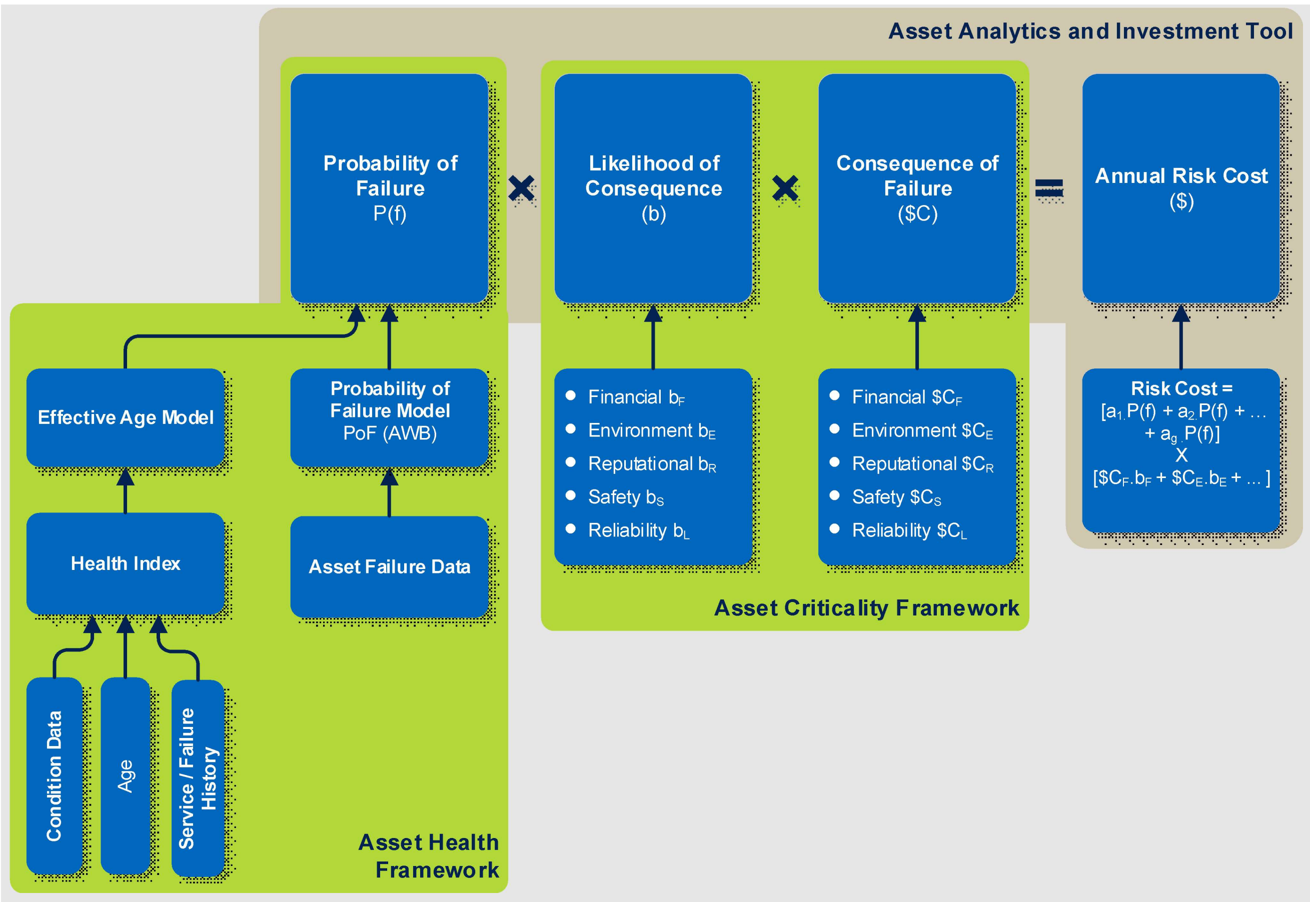
This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline[41] and its principles.

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 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 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

41 Industry practice application note - Asset replacement planning, AER January 2019

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

- bushfire risk;
- safety risk;
- environmental risk;
- reliability risk; and
- financial risk.

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

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

Appendix D Asset Health and Probability of Failure

The first step in calculating the Probability of Failure (PoF) of an asset is determining the asset health and associated effective age,[42] 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 Table below.

Further details are available in our Network Asset Health Methodology.

Table D-1 Weibull parameters for asset components

Asset	Weibull parameters	
	η	β
Oil filled Current Transformer	50	3.08
Capacitor bank	50	4.5
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

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

Asset	Weibull parameters	
	η	β
Remote Terminal Unit	22.5	1.77
PC	12.7	2.09
Meter - Microprocessor	15.5	1.74
DC Battery	16.5	1.49
DC Charger	19.8	1.24